Rhode Island Energy Efficiency Market Potential Study:

A Comprehensive Assessment of Demand-side Energy Resource (DER) Opportunities 2021-2026

(Volume I: Results)

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STATE OF RHODE ISLAND
ENERGY EFFICIENCY & RESOURCE MANAGEMENT COUNCIL

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CLIENTS

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List of Acronyms

AMF	Advanced metering functionality
ASHP	Air source heat pump
BYOD	Bring your own device
CBECS	Commercial Building Energy Consumption Survey
CHP	Combined heat and power
CRM	Community remote net metering
DCV	Demand control ventilation
DEEP	Dunsky Energy Efficiency Potential model
DER	Distributed energy resource
DLC	Direct load control
DMSHP	Ductless mini-split heat pump
DR	Demand response
EE	Energy efficiency
EEPP	Energy Efficiency Program Plan
EERMC	Rhode Island Energy Efficiency and Resource Management Council
EIA	Energy Information Agency
EISA	Energy Independence and Security Act of 2007
EMS	Energy management system
EUL	Effective useful life
GDP	Gross domestic product
GHG	Greenhouse gas
GIS	Geographic information system
GWh	Gigawatt-hour
HE	Heating electrification
HER	Home energy report
HPWH	Heat pump water heater
HVAC	Heating, ventilation, and air conditioning
ITC	Investment tax credit
LED	Light-emitting diode
MMBtu	One million British Thermal Units
MPS	Market potential study
MW	Megawatt
NEM	Net energy metering
NREL	National Renewable Laboratory
O&M	Operation and maintenance
OER	Rhode Island Office of Energy Resources

PUD	Pascoag Utility District
PV	Solar photovoltaic generation
REF	Renewable Energy Fund
REG	Renewable Energy Growth Program
RGGI	Regional Greenhouse Gas Initiative
SBC	Service benefit charge
tCO_2e	Tons of carbon-dioxide equivalent
TLED	Tubular light-emitting diode
TOU	Time of use rate
VNEM	Virtual net energy metering

Definitions

Term	Definition
Achievable potential	The savings from cost-effective opportunities once market barriers have been applied, resulting in an estimate of savings that can be achieved through demand-side management programs. For each module, three achievable potential scenarios are modeled to examine how varying factors such as incentive levels and market barrier reductions impact uptake.
Cumulative savings	A rolling sum of all new savings that will affect energy sales, cumulative savings exclude measure re-participation (i.e. savings toward a measure are counted only once, even if customers can participate again after the measure has reached the end of its useful life) and provide total expected grid-level savings.
Economic potential	The savings opportunities available should customers adopt all cost-effective savings, as established by screening measures against the Rhode Island Benefit Cost Test (RI Test), without consideration of market barriers or adoption limitations.
Energy end-use	In this study, energy end-uses refer to grouping of energy saving measures related to specific building component (i.e. water heating, HVAC, lighting etc.).
Incremental annual savings	Savings from measures incentivized through programs in a given year expressed in terms of savings in the first year of each measure's life. Incremental annual savings include savings attributable to measure re-participation (i.e. when a customer in incentivized to participate in a program again after the original measure has reached the end of its useful life).
Incremental lifetime savings	Savings from measures incentivized through programs in a given year expressed in terms of savings expected over the lifetime of each measure. Incremental lifetime savings include savings attributable to measure re-participation (i.e. when a customer in incentivized to participate in a program again after the original measure has reached the end of its useful life).
Market sector	The market of energy using customers in Rhode Island is broken down into four sectors based on the primary occupants in the building: residential (including single family and multi-family buildings), low-income residential, commercial, and industrial.
Market segment	Within each sector, market segments are defined to capture key differences in energy use and savings opportunities that are governed by building use and configuration.
Measure re-participation	The re-participation of a customer in a program after the original incentivized measure has reached the end of its useful life. Re-participation is counted in program savings (i.e. incremental lifetime savings and incremental annual savings), but it does not impact cumulative savings since the customer's net consumption is not impacted by replacing an efficient technology with an equally efficient technology.
Program Savings	Savings from measures incentivized through programs in a given year. Program savings include measure re-participation and are generally expressed in terms of incremental lifetime savings or incremental annual savings.
Annual Peak	The annual peak demand refers to the hour in each year that exhibits the highest system demand in MW, on a system-wide basis not accounting for local constraints.
RI Test	The Rhode Island Benefit Cost Test ("RI Test") is a cost-effectiveness test as approved by the Rhode Island Public Utility Commission in Docket 4755 and in accordance with the Docket 4600 Benefit-Cost Framework that compares the net benefits associated with the net savings of an efficiency measure or program over the life of the measure or program. For a full description of the costs and benefits included in the RI Test, please see the Attachment 4 - 2020 Rhode Island Test Description as filed with National Grid's 2020 EEPP (Docket No. 4979).

Executive Summary

E.1 Study Overview

This report presents the results of the Rhode Island Market Potential Study (MPS). The MPS includes five modules covering the following savings streams:

- Energy efficiency (EE),
- Electric demand response (DR),
- Combined heat and power (CHP),
- Heating electrification (HE), and
- Customer-sited rooftop solar photovoltaic (PV) generation.

The MPS covers the six-year period from January 1, 2021 to December 31, 2026 and includes electricity, natural gas, oil, and propane energy savings; passive electric demand reduction savings and active demand response savings; and the costs and benefits associated with these savings.

The study covers the entire State of Rhode Island, which is predominantly served by National Grid for electric and natural gas services. Therefore, the primary focus of this study and the majority of results presented within this report apply solely to National Grid's territory and customers – except when explicitly noted otherwise.

E.1.1 COVID-19

The MPS was conducted in the first quarter of 2020 – i.e prior to the onset of the COVID-19 pandemic. Accordingly, **the study does not consider the implications COVID-19 will have on achievable savings potentials**.

Directionally, COVID-19 is likely to place *downward pressure* on achievable *incremental* savings potential. At the time of this report's writing, widespread economic lockdowns and social distancing orders were still in effect in Rhode Island with uncertainty on when they will be relaxed. Additionally, the lasting economic impacts of COVID-19 are still unclear but are likely to result in a significant economic slowdown. Both economic slowdowns and new social distancing practices can serve to increase barriers for efficiency programs.

In addition to this downward pressure, the impacts of COVID-19 could also *shift* achievable potential and the relative economics of savings opportunities among measures, market segments, fuels, and end-uses due to factors such as:

- **Shifting energy use patterns,** e.g. as more people work from their homes, energy savings opportunities may shift somewhat from office buildings to residential, and peak demand reduction opportunities may change as peaks themselves shift in time and end-uses,

- **Shifting customer demographics and behavior,** e.g. higher incentives may be needed to account for a growth in low and moderate income customers (and reduced disposable income), small business owners with depleted cash reserves or greater debt, and greater risk aversion across the board, and
- **Changing relative fuel costs,** e.g. lower cost of delivered fuels could reduce the customer value proposition of electrification, while lower power supply costs could increase the value proposition for utilities.

These and other potential changes in savings opportunities could require a shift both in how programs are designed, and where program resources are directed in order to maximize program impacts and cost-effectiveness.

At the time of writing, however, neither the shape of the anticipated economic recovery nor the permanence of certain economic and social changes are predictable with any degree of confidence. As a result, the extent and distribution of COVID-19's impacts over the full six-year study horizon are equally uncertain. We therefore caution against coming to hasty conclusions and encourage further analysis to understand the possible implications of the pandemic for demand-side energy resource programs in Rhode Island.

E.2 Energy Efficiency

The energy efficiency (EE) module estimates energy savings for electric, natural gas, and delivered fuel (oil and propane) efficiency measures as well as peak demand savings (i.e. passive demand reductions) for electric measures. Three achievable program scenarios are explored as described in Figure E-1.

Figure E-1. EE Module Program Scenario Descriptions

Low	Applies incentives and enabling activities in line with National Grid's 2020 Energy Efficiency Plan to simulate **business as usual.**
Mid	Increases incentives and enabling activities **above and beyond** levels within National Grid's 2020 Energy Efficiency Plan.
Max	Completely eliminates customer costs to further reduce customer adoption barriers to estimate **maximum achievable potential.**

Efficiency savings estimates are benchmarked against savings achieved in 2019 and savings planned for 2020. Savings achieved in 2019 are taken from the 2019 Energy Efficiency Fourth Quarter Report, which provides draft efficiency savings achieved for the entire 2019 calendar year ("Draft 2019 Results").[1] Savings planned for 2020 are taken from the 2020 Energy Efficiency Program Plan as filed by National Grid ("2020 EEPP").[2]

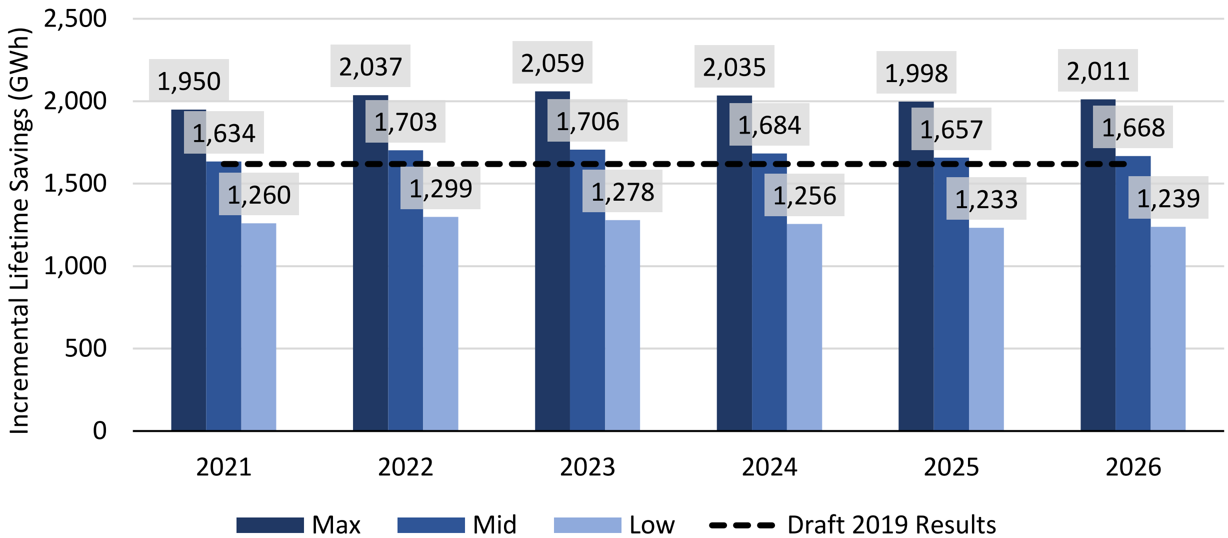
E.2.1 Electric Program Savings

The study estimates that efficiency programs can procure an average of 1,261 GWh (Low) to 2,015 GWh (Max) of incremental lifetime savings each year during the study period as shown in Figure E-2. This represents between 47% (Low) to 73% (Max) of economic savings.[3] Slight fluctuations in yearly savings are observed as savings ramp up from measures that are not significant components of existing efficiency

[1] The 2019 Energy Efficiency Fourth Quarter Report was presented at the February EERMC meeting and is accessible at: http://rieermc.ri.gov/wp-content/uploads/2020/02/2019-ri-fourth-quarter-highlights-final-ri-puc.pdf. A final report for 2019 is scheduled to be filed with the RI PUC in May 2020 and may differ from the draft report referenced in this study.
[2] National Grid's 2020 EEPP (Docket No. 4979) is accessible at: http://www.ripuc.ri.gov/eventsactions/docket/4979page.html.
[3] Economic savings are savings from measures that pass the Rhode Island Benefit Cost Test ("RI Test") as approved by the Rhode Island Public Utility Commission in Docket 4755 and in accordance with the Docket 4600 Benefit-Cost Framework.

programs in the first three years of the study and savings from speciality and reflector bulbs become unavailable in 2023.[4]

Figure E-2. Incremental Lifetime Electric EE Savings by Year (2021-26; All Scenarios)



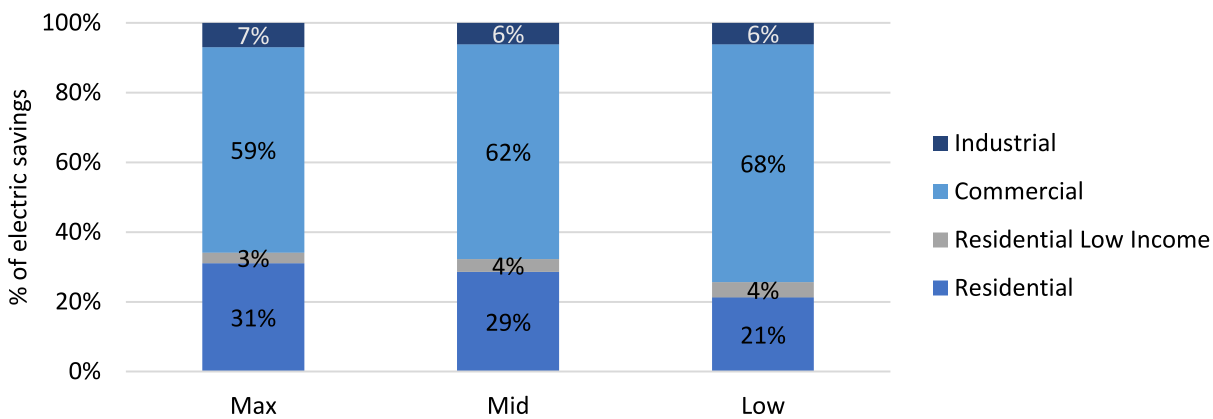
Compared to National Grid's Draft 2019 Results (1,619 GWh) and the 2020 EEPP (1,474 GWh), electric efficiency program savings under business-as-usual conditions (i.e. Low scenario) will be lower throughout the study period. This is primarily due to the exclusion of savings from standard light bulbs (A-Lamps) – which are a significant component of savings in current programs – as the study assumes LEDs will become the new baseline technology for standard bulbs by 2021. However, the Mid scenario offers similar levels of savings to those achieved by National Grid in 2019, and the Max scenario represents an opportunity to significantly increase savings above current levels.

Program Savings by Market Sector

Across all scenarios, the bulk of electric efficiency savings come from the commercial sector as shown in Figure E-3. However, as total savings grow under the Mid and Max scenarios, savings from the residential sector increase at a faster rate as indicated by their increasing share of overall savings under the Mid and Max scenarios. This result suggests the opportunity to increase savings by investing in new measures, higher incentives, and further enabling strategies is particularly pronounced in the residential sector.

[4] The study assumes that savings from specialty and reflector bulbs become unavailable in 2023 due to either market transformation or the enforcement of the 2007 Energy Independent and Security Act (EISA) "backstop" mechanism.

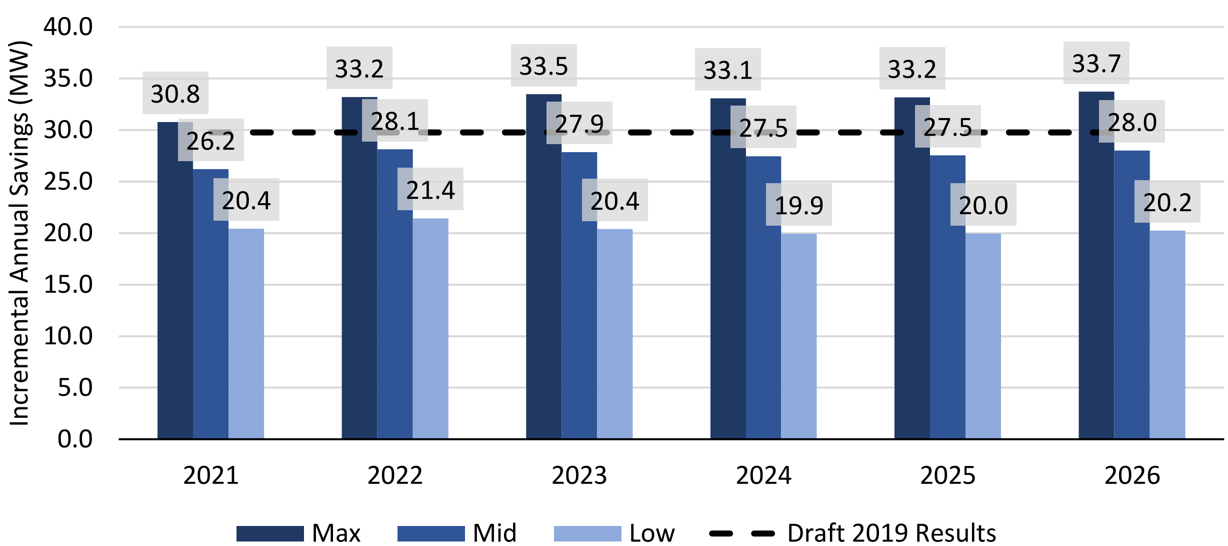
Figure E-3. Proportion of Electric EE Savings by Sector (2021-26 Average Incremental Lifetime Savings; All Scenarios)



Passive Demand Reductions

In terms of passive demand reductions, incremental annual savings range from an average of 20.4 MW (Low) to 32.3 MW (Max) across the study period as shown in Figure E-4. Relative to 2019 Draft Results (29.8 MW) and the 2020 EEPP (29.6 MW), passive demand reductions under the Low and Mid scenarios are low, which is driven by the loss of savings from standard bulbs as claimed in current programs.

Figure E-4. Incremental Annual Electric EE Demand Savings by Year (2021-26; All Scenarios)

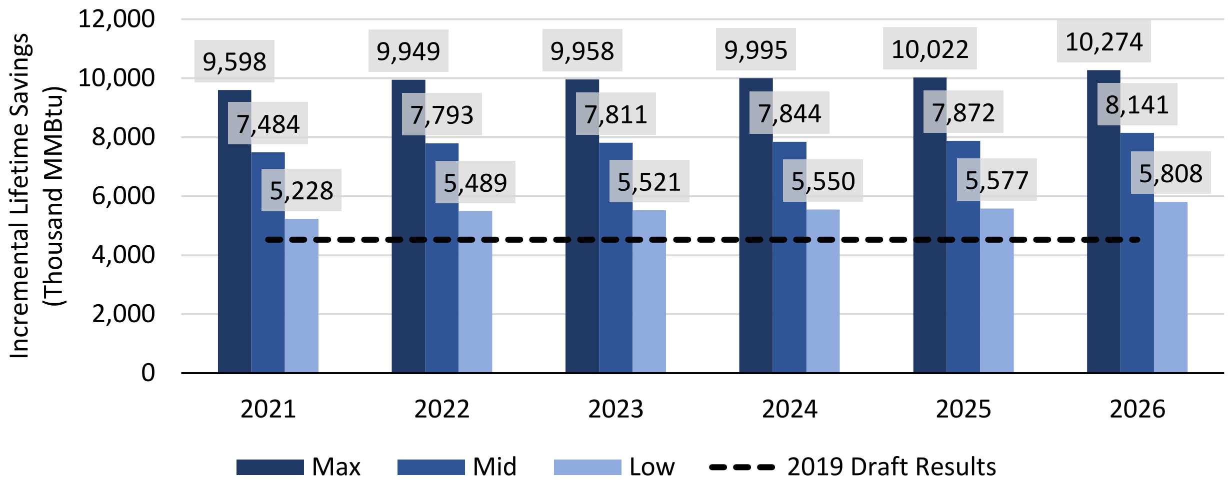


Note: The above figure represents passive demand reductions from EE measures and not including active demand response.

E.2.2 Natural Gas Program Savings

The study estimates that efficiency programs can procure an average of 5,529 thousand MMBtu (Low) to 9,966 thousand MMBtu (Max) of incremental lifetime savings each year. This represents between 48% (Low) to 79% (Max) of the economic savings. As shown in Figure E-5, incremental lifetime savings grow year-over-year – particularly between 2021 and 2022 as measures ramp up.

Figure E-5. Incremental Lifetime Natural Gas EE Savings by Year (2021-26; All Scenarios)

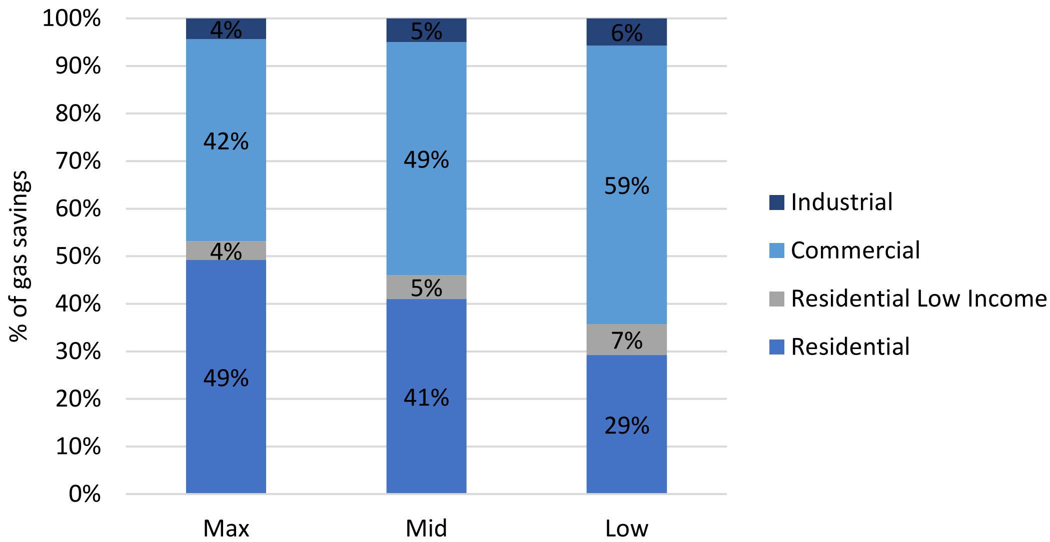


Compared to Draft 2019 Results (4,525 thousand MMBtu) and the 2020 EEPP (4,816 thousand MMBtu), the study estimates that natural gas efficiency savings under business-as-usual (i.e. Low scenario) are higher than achieved in 2019 or planned for 2020. Under the Low scenario, incremental lifetime savings in 2021 are approximately 8.5% higher than the 2020 EEPP. This is a similar rate of increase in incremental lifetime savings indicated between the Draft 2019 Results and the 2020 EEPP, where a 6.5% increase is predicted.

Program Savings by Market Sector

Under the Low scenario, the bulk of natural gas savings come from the commercial sector as shown in Figure E-6. However, as incentives and enabling activities increase under the Mid and Max scenarios, savings from the residential sector grow at a much faster rate than other sections. Similar to electric efficiency measures, savings from the residential sector increase at a faster rate between the Low and Max scenarios relative to other sectors - suggesting the opportunity to increase savings by investing in new measures, higher incentives, and further enabling strategies is particularly pronounced in the residential sector for natural gas as well.

Figure E-6. Natural Gas EE Savings by Sector (2021-26 Average Incremental Lifetime Savings; All Scenarios)

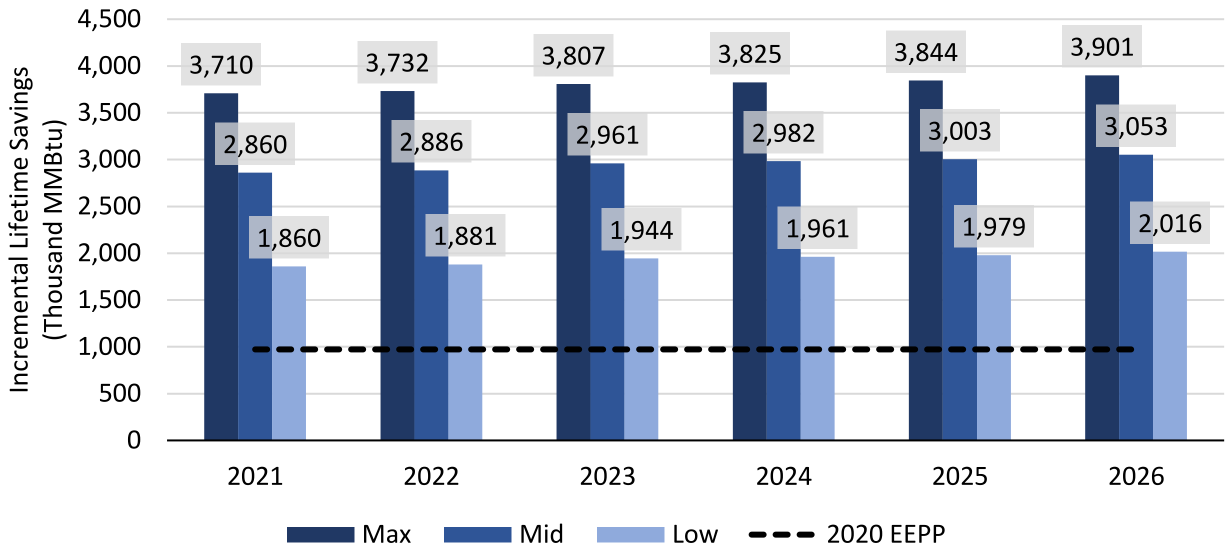


E.2.3 Delivered Fuel Savings

The study estimates that efficiency programs can procure an average of 1,940 thousand MMBtu (Low) to 3,803 thousand MMBtu (Max) of incremental lifetime savings in delivered fuels each year during the study period. This represents between 47% (Low) to 75% (Max) of economic savings.[5] As shown in Figure E-7, incremental lifetime savings grow slightly year-over-year.

[5] Economic savings are savings from measures that pass the Rhode Island Benefit Cost Test ("RI Test") as approved by the Rhode Island Public Utility Commission in Docket 4755 and in accordance with the Docket 4600 Benefit-Cost Framework.

Figure E-7. Incremental Lifetime Delivered Fuel EE Savings by Year (2021-26; All Achievable Scenarios)



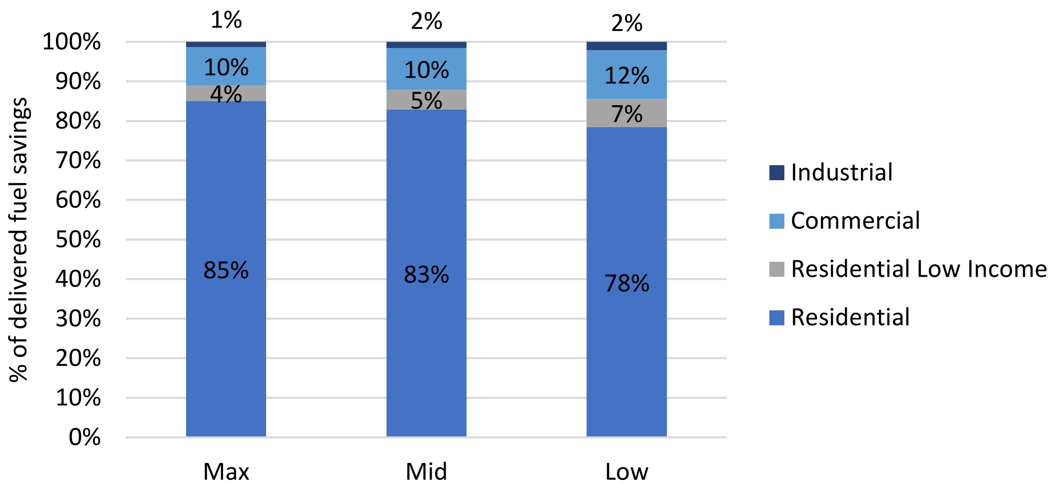
Note: National Grid's Draft 2019 Fourth Quarter Report did not include oil and propane savings, therefore the 2020 EEPP benchmark is included in the above figure.

Compared to the 2020 EEPP (972 thousand MMBtu), the study finds significantly more delivered fuel savings than are currently planned through existing programs as National Grid offers a limited set of measures for residential customers and no measures for commercial and industrial customers that claim delivered fuel savings due to historically limited approved funding for these measures. The study estimates the potential for delivered fuel efficiency savings under the Low scenario is more than double the savings assumed in the 2020 EEPP Plan.

Program Savings by Market Sector

As shown in Figure E-8, the vast majority of delivered fuel savings under each scenario come from the residential sector with 78% (Low) to 85% (Max) of average incremental lifetime savings, which is greater than the residential sector's share of overall delivered fuel consumption in Rhode Island (approximately 70%).

Figure E-8. Proportion of Delivered Fuel EE Savings by Sector (2021-26 Average Incremental Lifetime Savings; All Scenarios)



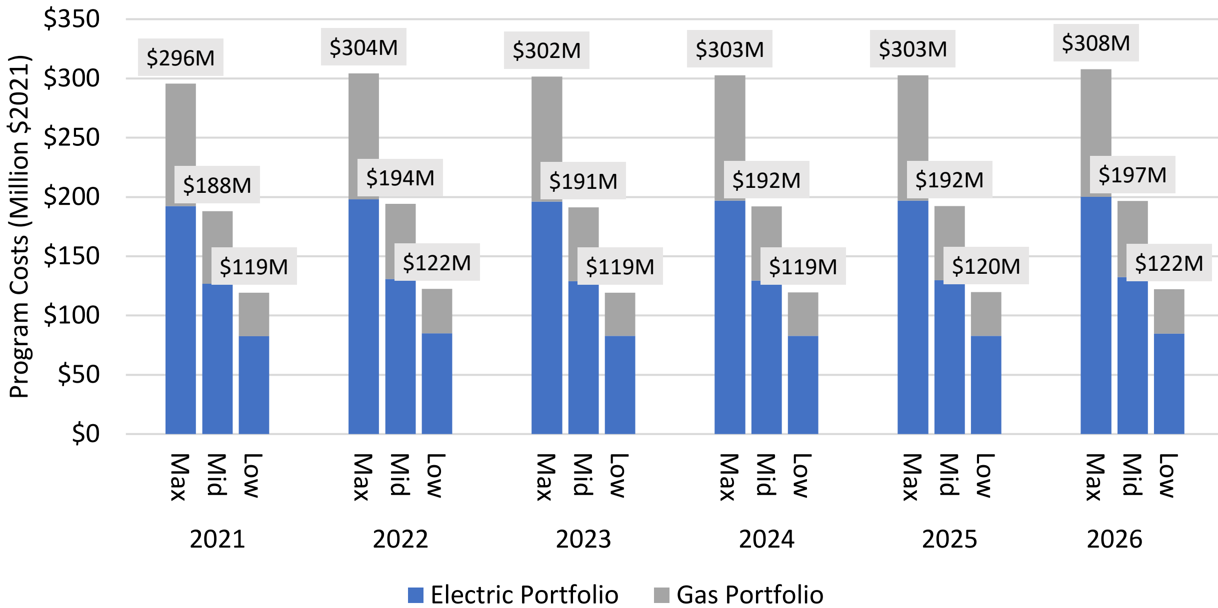
E.2.4 Portfolio Metrics

Program Costs

The study estimates that efficiency program costs will range between an average of $120 (Low) to $302 (Max) million per year. Similar to current efficiency spending, the majority of this is directed toward the electric efficiency programs as seen in Figure E-9, which also includes spending on delivered fuel measures. Relative to Draft 2019 Results ($99M) and the 2020 EEPP Plan ($101M), the study estimates a reduction in the annual program spending under a business-as-usual approach (i.e. Low scenario).[6] This is primarily driven by the elimination of program spending on A-Lamp measures in the study, which accounts for roughly $7.9 million of 2019 spending (8% of electric portfolio spending) and $6.4 million of the 2020 EEPP (6% of electric portfolio spending).[7]

[6] Benchmark spending metrics do not include spending on CHP, DR, or HE.
[7] Spending specific to A-Lamp measures was provided directly by National Grid. The remainder of the difference may be attributable to additional costs within the reporting spending in 2019 and planned in 2020 that are not accounted for in the study (e.g. regulatory costs) as well as inherent uncertainty involved in large-scale potential studies.

Figure E-9. Estimated EE Program Costs by Year (2021-26; All Scenarios)



Note: Electric portfolio costs include incentive and implementation costs for delivered fuel measures.

In addition to larger budgets, the average unit cost of savings increases as well under the Mid and Max scenarios as shown in Table E-1. This result is likely driven by two factors. First, raising incentives increases the cost not just for newly acquired savings, but for all savings that would have been obtained under lower incentive levels and thus at a lower per unit cost. Second, the higher incentives and investments in enabling strategies may drive more uptake of measures with higher unit savings costs associated with their lower savings to incremental cost ratios.

Table E-1. Average Estimated EE Savings Cost per Unit of Incremental Lifetime Savings (2021-26; All Scenarios)

Metric	Max	Mid	Low	2019 Results	2020 Plan
$ per Incremental Lifetime kWh	$0.098	$0.077	$0.066	$0.065	$0.069
$ per Incremental Lifetime MMBtu	$10.61	$8.02	$6.68	$6.66	$6.80

While higher program costs are to be expected under scenarios with increased incentives and higher customer participation, the precise magnitude of cost increases under these scenarios should be interpreted with the understanding that the study's program cost estimates are based on historical program expenditures and strategies, and the scenarios in the study are not optimized for program spending. Cost structures in the future may not reflect historical costs – especially as programs shift away from lighting. Additionally, the study sets incentive levels at the program level (i.e. all measures under a program receive the same incentive as a percentage of incremental costs) when real-world program design would likely set unique incentive levels for each measure based on market realities to optimize the expenditure of program resources. A more granular approach to incentive setting could lead to significantly lower program costs at minimal expense of reducing savings.

Program Benefits

In all scenarios, efficiency savings create significant benefits to rate payers, customers, and society at large. Based on the RI Test, the average net lifetime benefits generated each year from measures incentivized each year range from $446 million (Low) to $910 million (Max) as shown in Table E-2. These benefits include an average annual addition of $272 (Low) to $642 (Max) million to Rhode Island's state gross domestic product (GDP) each year resulting from investments in energy efficiency.

Efficiency savings will also generate significant net bill savings for participating customers. Each year, the study estimates efficiency programs will result in an average of $396 (Low) to $688 (Max) million dollars of net bill savings for customers over the lifetime of the installed measures as shown in Table E-2.[8]

Finally, the adoption of efficiency measures will also lead to significant greenhouse gas (GHG) emissions reductions. In each year of the study period, efficiency measures are projected to reduce annual emissions by between 90,000 (Low) to 147,000 (Max) short tons of carbon-dioxide equivalent (tCO_2e) on average as shown in Table E-2. By 2026, Rhode Island's annual emission footprint will be reduced by 539,000 to 879,000 tCO_2e, which is roughly equivalent to removing 105,000 to 172,000 passenger vehicles from the road for a year.[9] This would decrease Rhode Island's emissions by a further 3.9% to 6.4% relative to the 1990 baseline emission level of 13.8 million tCO_2e.[10]

Table E-2. Summary of Net EE Benefits Generated Each Year (2021-26 Average; All Scenarios)

Benefit	Max	Mid	Low
Lifetime RI Test Net Benefits (2021$)	$910M	$635M	$446M
Economic Development Benefits (2021$)	*$642M*	*$410M*	*$272M*
Lifetime Customer Net Bill Savings (2021$)	$688M	$537M	$396M
GHG Emission Reductions (tCO_2)	147,000	121,000	90,000

Note: Lifetime RI Test Net Benefits include Economic Development Benefits

E.2.5 Key Takeaways

Rhode Island has the potential to capture a significant portion of cost-effective efficiency savings over the study period leading to substantial economic and environmental benefits. For all fuel types, the Max scenario captures between 73% to 80% of all economic savings opportunities. These savings can generate up to $910 million in net lifetime benefits for Rhode Island each year on average, which includes $642 in economic development benefits. These efficiency savings will also generate up to $688 million in lifetime customer bill savings and 879,000 tCO2e of emission reductions each year.

[8] Lifetime customer net bill savings are calculated by summing the annual bill savings over the effective lifetime of the measure and subtracting the portion of the measure's incremental cost paid by the customer (e.g. the customer pays 70% of the incremental cost when the utility offers a 30% incentive).

[9] Passenger vehicle estimate calculated using the EPA Greenhouse Gas Equivalencies Calculator accessible at: https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator

[10] *2016 Rhode Island Greenhouse Gas Inventory, Draft Version 1*. Accessed at: http://www.dem.ri.gov/programs/air/documents/righginvent16-d.pdf. 1990 baseline of 12.48 million metrics tons of CO_2e converted to short tons at rate of 1.102 short tons per metric ton.

Achieving this level of savings however will likely require updating some programs and strategies as many of the residential lighting opportunities leave the market and new opportunities emerge. The study estimates that achieving these savings could carry significant program costs – reaching approximately $300 million per year – although the study applied historical program costs and delivery approaches and did not include an attempt to optimize program designs around cost.

The opportunity exists to grow savings for electric efficiency programs, even as a large portion of lighting savings leave the market. The loss of claimable savings from standard (A-Lamps) and specialty bulbs will significantly reduce lighting program savings as compared to recent years. However, by investing in new measures, higher incentives, and further enabling strategies, more electric savings can be captured in other end-uses. In particular, increasing the adoption of measures with longer useful lives and savings persistence will more than make up for the loss of lighting savings when savings are measured in terms of incremental lifetime savings.

Natural gas savings will grow in importance in the energy efficiency portfolio. As natural gas consumption continues to increase in Rhode Island, so will the opportunity for efficiency savings. The study estimates there is continued room for savings growth – even under business-as-usual conditions.

The opportunity for growing savings is particularly pronounced in the residential sector. While there is the potential for savings growth in all sectors, the relative opportunity for growth is much larger in the residential sector between business-as-usual conditions (i.e. the Low scenario) and Mid/Max compared to other sectors. For electric measures, residential savings increase by 79% to 134% under the Mid and Max scenarios relative to the Low scenario, respectively. For gas measures, residential savings increase by over 100% to 200% under the Mid and Max scenarios, respectively.

E.3 Demand Response

The active peak demand reduction potential, herein referred to as DR potential, is assessed by analyzing the ability for behavioral measures, equipment controls and industrial and commercial curtailment to reduce the system wide annual peak demand.[11] A sensitivity of these results to the possible roll out of advanced metering functionality (AMF) by 2024 is also included in the study.

The DR potential is assessed against National Grid's system hourly load curve and annual peak demand.[12] A standard peak day 24-hour load curve is identified and adjusted to account for projected load growth, efficiency program impacts and solar PV installations over the study period. Achievable savings are expressed in the impact on the annual peak, accounting for load shifting and new peak hours that may arise as results of demand recharge or rebound effects from DR measures.[13]

The achievable potential is assessed under three scenarios corresponding to varied DR approaches or strategies (Figure E-10). These scenarios deliver varying benefits covering a range of peak demand impacts.

Figure E-10. DR Module Program Scenario Descriptions

Low	Applies National Grid's current DR programs and incentive levels, allowing them to expand to their full extent across the applicable market. This provides a **business as usual** case.
Mid	Applies an **expanded list of DR measures and programs,** adding new equipment controls measures, either through utility direct load control, or manual controls, in addition to current curtailment programs.
Max	Applies the expanded list of DR measures and programs, but with **incentives increased to the maximum feasible level** to maintain measure-level cost-effectiveness.

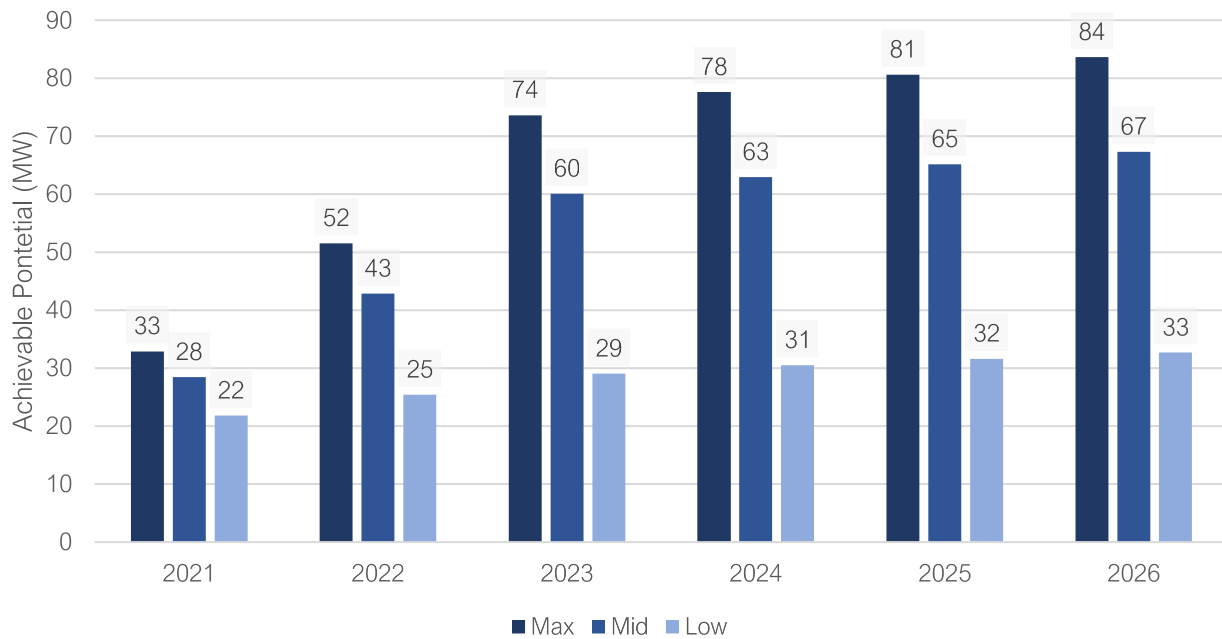
E.3.1 Active Demand Savings

The overall achievable potential in each year for each scenario is presented below (Figure E-11). These results present the overall peak load reduction potential when all the constituent programs are assessed together against the utility load curve, accounting for the combined interactions among programs, and reasonable roll out schedules.

[11] In all cases in this report, the annual peak demand refers to the hour in the year that exhibits the highest system peak demand in MW. It is assessed on a system-wide basis, not accounting for local constraints across the transmission and distribution system.
[12] The impacts of DR programs on the ISO New England load curve are not covered in this study.
[13] This differs from how National Grid reports DR program results, wherein the impacts are expressed in terms of the reduction in load during DR event windows only. A comparison of these approaches is provided in the body of the report, and achievable potential results expressed in equivalent terms to how National Grid reports impacts are provided in Appendix G.

Under the Low scenario, which represents National Grid's current programs expanded to their full extent, the potential is estimated to grow from 22MW in 2021 to 33MW in 2026, which represents 1.7% of National Grid's peak in 2026. Under the Mid and Max scenarios, the achievable potential estimates respectively achieve 67MW and 84MW in 2026, translating into 3.6% and 4.5% of National Grid's peak. Based on these results, the scenario analysis indicates that expanding the number and types of DR programs and measures can provide more DR potential than simply expanding current programs.

Figure E-11. Demand Response Achievable Potential (All Scenarios)



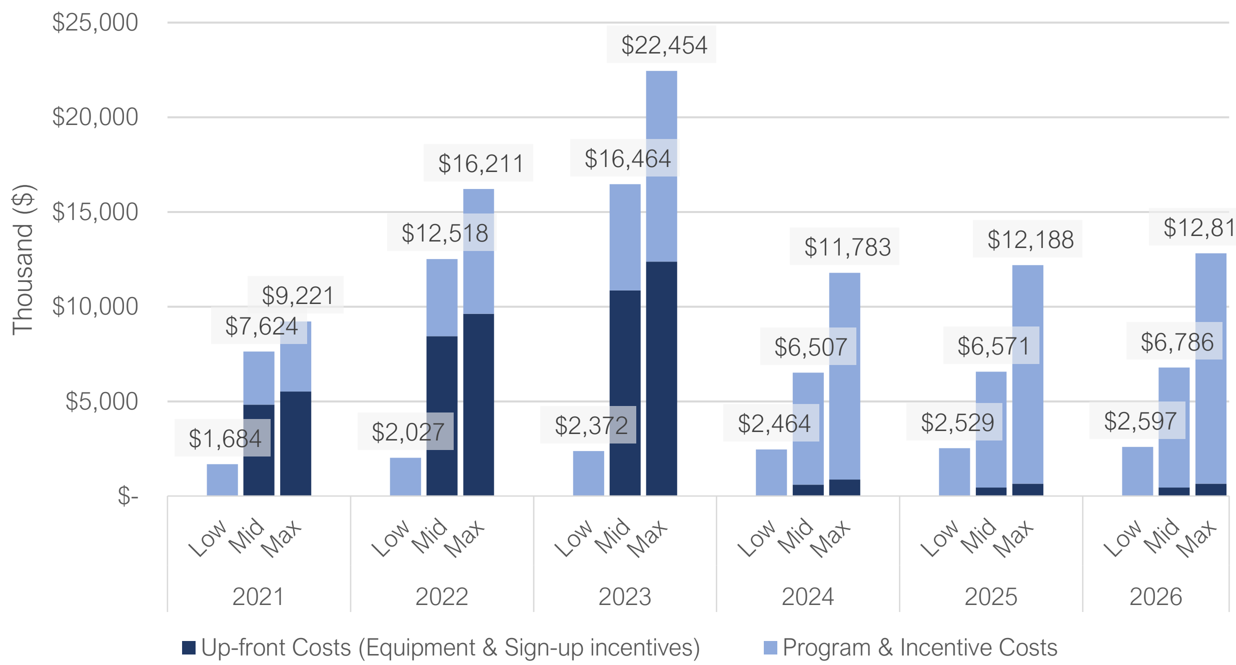
E.3.2 Portfolio Metrics

Program Costs

Program spending is projected to range between $1.7 to $2.6 million per year under the Low Scenario, and reaching as high as $22 million in the Max scenario (Figure E-12). In all scenarios, the results show significant up-front costs[14] in the initial years as new customers are enrolled in the programs and new controls systems are put in place, followed by a greater emphasis in the later years on incentives to maintain participation in the programs.

[14] Upfront measure costs include sign-up (enrollment) incentive costs, as well as controls and equipment installation costs.

Figure E-12. Demand Response Program Costs (All Scenarios)



Program Benefits

DR program investments offer significant benefits under all scenarios (Table E-3). It is worth noting that the Mid and Max scenarios have significantly higher associated economic benefits due to the prevalence of commercial and industrial sector program peak savings, which are higher than residential program peak savings economic benefits. This helps to support the Mid and Max scenario RI Test cost-effectiveness values, despite the significantly higher program costs associated increased incentive levels.

Table E-3. Demand Response RI Test Benefits (All Scenarios)

Benefit	Max	Mid	Low
Lifetime RI Test Net Benefits (2021$)	$407M	$300M	$107
Economic Development Benefits (2021$)	*$251M*	*$182M*	*$67.9M*

Note: All benefits are based on a 10-year assumed program life. Lifetime RI Test Net Benefits include Economic Development Benefits

E.3.3 AMF Sensitivity

The sensitivity of the Mid Scenario results to the installation of AMF is assessed at two levels. The first considers just the ability for AMF to reduce controls equipment costs for certain measures, such as residential water heater direct load controls measures. The second accounts for the ability to include Time-of-Use (TOU) rates regimes to reshape customer demand.

Overall, these results show that AMF without TOU could slightly increase the Mid Scenario potential, by facilitating higher incentives to customers as controls equipment costs to utilities would be slightly lower than for DLC measures (Table E-4) More notable, the application of an opt-out TOU rate regime enabled by AMF would increase the Mid Scenario potential to 109 MW, 56 MW of which is derived from TOU rate impacts. The TOU rates do however lower the benefits from certain DLC type measures, where it is assumed that the load shift has largely been accomplished by a change in customer behavior in response to avoid peak rate charges.

Table E-4. Mid Scenario Compared to the Max and TOU Scenarios

Scenarios	Mid Scenario	Max Scenario	Mid Scenario + AMF (no TOU)	Mid Scenario + AMF (with TOU)
Achievable Potential (MW)	67	82	72	109

E.3.4 Key Takeaways

Based on the findings in this report three key take-aways emerge:

- **There is significant opportunity to expand DR programs in RI in a cost-effective manner, both through growing the market for existing programs, and introducing new measures and programs.** Both the Low and Mid scenarios demonstrate notable increase in DR potential over current DR program performance. Most of the potential expansion is concentrated in Wi-Fi Thermostats and Commercial Energy Storage. The first would be an expansion of an existing program, while the second would be a new program with the utility providing a capital incentive for thermal or battery energy storage initial costs.

- **Expanding to new DR programs can generate demand savings more cost-effectively than just increasing incentives.** By 2026 the Mid scenario (expanded with new programs) offers an additional 34MW of potential over the Low scenario (current programs extended over the full market), with the Mid scenario returning a RI Test values of 3.8 compared to the RI Test of 4.7 for the Low scenario. The Max scenario offers a further 17MW of potential, but at a twofold increase in program costs and yielding a reduced RI Test result of 2.8 by 2026.

- **The Rhode Island peak day curve is currently well suited for commercial curtailment, but as solar distributed generation and EV penetration increase, residential sector will become an increasing important source of DR potential.** The current peak occurs in summer afternoons, which is highly coincident with commercial building loads such as cooling and ventilation. Expected changes in demand caused by solar PV and EV adoption will shift the afternoon peak to later in the day, thereby decreasing the coincidence with commercial loads, and increasing the coincidence with residential loads.

Overall, it appears that adding new measures, while expanding the current programs is the best option to optimize the DR achievable potential in Rhode Island. When considering new programs, or the expansion of existing programs in RI, those programs should be assessed against the projected load curve shapes for 5 and 10 years into the future to determine which strategies will best fit RI's changing peak management needs. Moreover, investments in residential DLC programs should considered in light of possible TOU rate regimes (enabled by AMF) in the future, as a broad TOU rate application could undermine prior investments in DLC programs.

E.4 Combined Heat and Power

The CHP module estimates the technical, economic, and achievable potential for CHP in Rhode Island. Technical and economic CHP potential is estimated using a bottom-up approach that estimates optimal CHP system sizes on a per customer basis by analyzing monthly gas customer billing data as a proxy for thermal loading.

Technical potential is estimated by sizing CHP systems to cover 100% of the customer's eligible thermal load regardless of customer economics.

Economic potential is estimated by sizing CHP systems to ensure a RI Test benefit-cost ratio greater than 1 and a reasonable customer payback.

Achievable potential is then estimated by applying technology adoption and diffusion theory as captured through the Bass Diffusion Curve.[15] Due to the limited number of appropriate sites in each non-residential market segment achievable, potential results are assessed and presented as annual averages across the entire non-residential market.

The CHP module explores three program scenarios as summarized in Figure E-13.

Figure E-13. CHP Module Program Scenario Descriptions

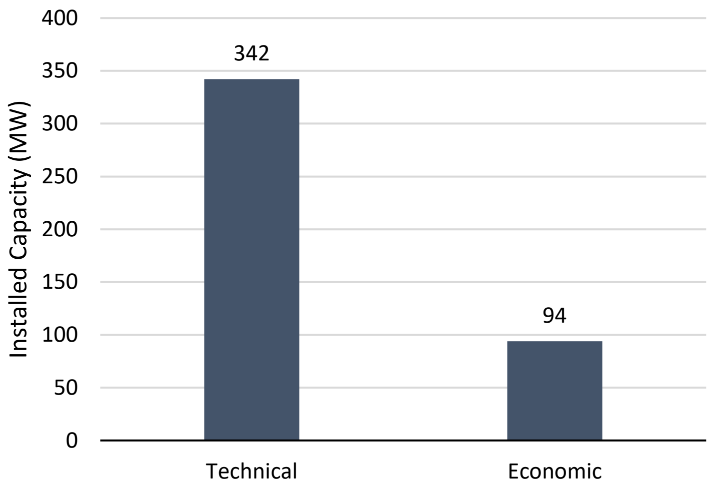
Low	Incentives levels are set at the **maximum allowable incentive level of 70%** of project capital costs with adoption barrier levels set to reflect historical adoption in Rhode Island.
Mid	Incentives levels are set at the maximum allowable incentive level of 70% of project capital costs with **adoption barrier levels reductions** to simulate additional market barrier reductions.
Max	**Incentive levels set at 100%** of project capital costs with the same barrier level reductions as the Mid scenario.

E.4.1 Technical and Economic Potential

The study estimates there is approximately 342 MW of technical potential in terms of installed capacity in Rhode Island. This result represents the amount of CHP that might be expected if all applicable thermal load was supplied by CHP systems regardless of customer economics. When CHP systems are sized with customer payback in mind, only 94MW of the technically feasible capacity is considered economic representing approximately 27% of technical potential as shown in Figure E-14.

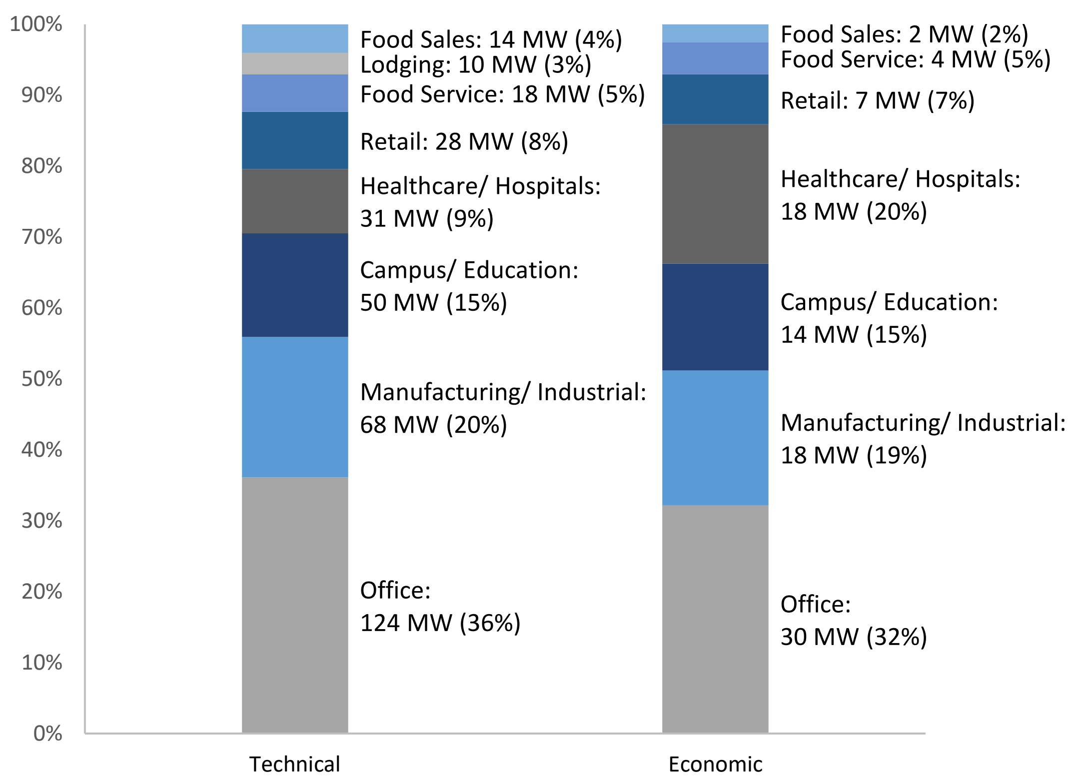
[15] The Bass Diffusion Curve (also referred to as the Bass Model or Bass Diffusion Model) is a simple differential equation that models the adoption of technology over time in a given population.

Figure E-14. Technical and Economic CHP Potential (Installed Capacity)



At the segment level, the largest amount of CHP potential is found in the office segment with significant amounts of potential in the manufacturing & industrial, campus & education, and healthcare & hospitals segments as shown in Figure E-15.

Figure E-15. Proportion of Technical and Economic CHP Potential by Segment



The significant amount of CHP potential in the manufacturing & industrial, campus & education, and healthcare & hospitals segments is driven by the large thermal loads in these facilities, and this finding is supported by the concentration of existing CHP systems in these segments. However, the large proportion of CHP potential in office buildings is a somewhat surprising result, which may be an artefact of gaps in the customer data used for this analysis, which did not include segment identification information for many customer accounts. Additional market research would be valuable to validate or refute this finding.

E.4.2 Achievable Potential

Under the Low and Mid scenarios, the study estimates that CHP programs could incentivize 3.5 MW (Low) to 4.5 MW (Mid) of additional installed CHP capacity per year during the study period. Under the Max scenario, CHP adoption significantly increases to approximately 11.1 MW of capacity per year. The large increase in annual capacity additions under the Max scenario relative to the Low and Mid scenarios suggests that customer economics is a limiting factor for CHP adoption in Rhode Island, while the relatively smaller difference between the Mid and Low scenarios suggests that reducing market barriers will have a limited – although not negligible – impact on adoption.

Table E-5 presents the expected electric energy and peak demand savings, gas consumption increases, and annual program costs under each scenario associated with these capacity additions.

Table E-5. Achievable CHP Potential Summary Table (2021-2026 Averages; All Scenarios)

Impact	Max	Mid	Low
Annual Capacity Additions (MW)	11.1	4.5	3.5
Incremental Lifetime Electric Savings (MWh)	723,337	296,409	225,700
Incremental Annual Demand Reductions (MW)	4.12	1.69	1.28
Annual Gas Consumption Increase (MMBtu)	266,891	109,366	83,277
Annual Program Costs (Million $2021)	$29.6M	$9.0M	$6.7M

Benefits

Based on the RI Test, the average annual net benefits generated each year range from $26 million (Low) to $84 million (Max). These benefits account for the increase in natural gas consumption that will occur and include an average annual addition of $19 million (Low) to $63 million to Rhode Island's state gross domestic product each year resulting from "the effects of program and participant spending that creates jobs in construction and other industries as the project is planned, and equipment is purchased and installed". [16]

A key benefit of CHP is the efficiency gains resulting from simultaneously producing useful thermal and electricity onsite, which can achieve efficiencies greater than 80%, while using electricity from the grid and producing on-site thermal energy only typically has an efficiency in the range of 45-55%. When these efficiency gains are considered, CHP adoption could reduce net energy consumption by an equivalent of 101 thousand MMBtu (Low) to 325 thousand MMBtu (Max) per year by 2026. This net reduction in

[16] For a full description of the benefits and costs included in the RI Test, please see the Attachment 4 - 2020 Rhode Island Test Description as filed with National Grid's 2020 EEPP (Docket No. 4979) accessible at: http://www.ripuc.ri.gov/eventsactions/docket/4979-NGrid-EEPP2020%20(10-15-19).pdf

energy consumption will result in an annual reduction in emissions of approximately 11 to 34 thousand tons of CO_2, which is equivalent to removing 2,400 to 7,300 passenger vehicles from the road for a year.[17]

E.4.3 Key Takeaways

Additional CHP potential exists, and current incentive levels can encourage adoption over the study period that is commensurate with recent years. Customer natural gas consumption in Rhode Island suggests there is a continued opportunity to supply thermal demands with CHP.

The biggest opportunities for further CHP adoption fare in the Office, Healthcare & Hospitals, Education & Campus, and Manufacturing & Industrial segments. Relatively larger opportunities in the latter segments is not surprising based on typical CHP applications, but the significant potential in the Office segment represents a potential new opportunity or CHP deployment in Rhode Island. However, due to limitations in accurately segmenting customer data, further market research should be conducted to validate these findings.

Reducing non-financial barriers through enabling activities may move the market a little, but overall impact is small compared to increasing customer payback (e.g. increased incentives). The up-front capital costs of CHP are often a significant hinderance to CHP adoption.

[17] Passenger vehicle estimate calculated using the EPA Greenhouse Gas Equivalencies Calculator accessible at: https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator

E.5 Heating Electrification

The HE module estimates the potential for replacing or retrofitting existing heating systems with air source heat pumps (ASHPs) and ductless mini-split heat pumps (DMSHPs) to displace heating from fossil-fuel based (natural gas, oil, and propane) space and water heating systems over the study period.[18] The study estimates the program savings expressed as fuel savings associated with electrifying these systems as well as the commensurate impact on electricity consumption and peak demand that will occur with heating electrification. The study considers both the *increase* in electricity consumption that will occur from using electric heat pumps to provide space and water heating as well as any *decreases* that may occur from the provision of more efficient space cooling from heat pumps adopted for heating purposes.

The HE module explores three program scenarios as described in Figure E-16.

Figure E-16. HE Program Scenario Descriptions

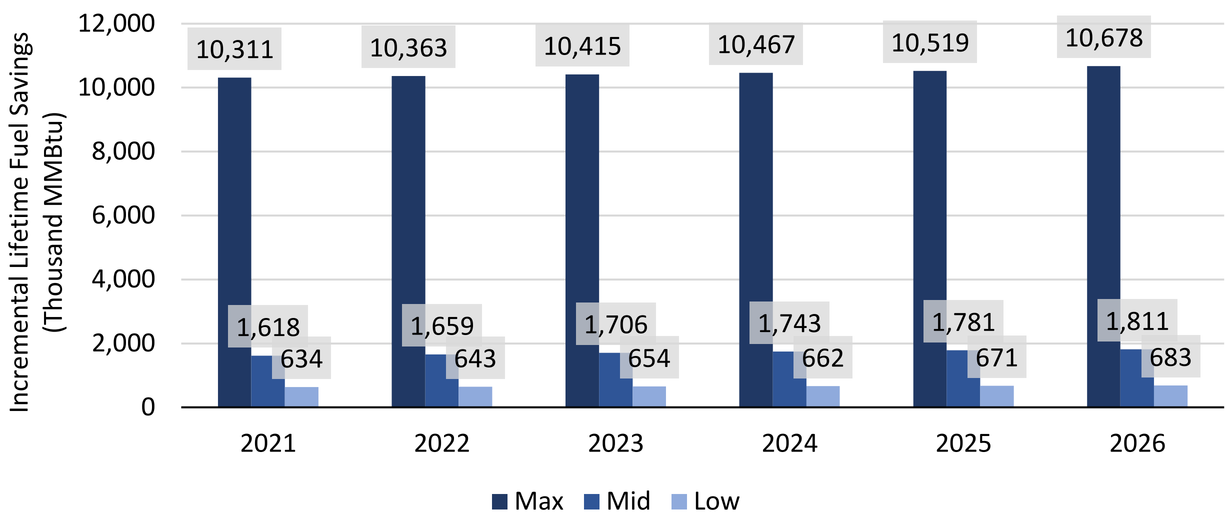
Low	Applies 25% incentives and enabling activities in line with National Grid's proposed 2020 Energy Efficiency Program Plan, except for the residential low-income sector, which continues to receive a 100% incentive.
Mid	Applies 50% incentives and additional enabling strategies, except for the residential low-income sector, which continues to receive a 100% incentive.
Max	Incentives set at 100% to completely eliminate customer costs and applies same enabling strategies as under Mid scenario.

E.5.1 Program Savings

The study estimates that heating electrification programs can procure an average of 658 thousand MMBtu (Low) to 10,453 thousand MMBtu (Max) of incremental lifetime fuel (natural gas, oil, and propane) savings each year during the study period as shown in Figure E-17. The vast majority of program savings come from displacing delivered fuel space and water heating and relatively little come from displacing natural gas heating. This is due to most natural gas electrification potential failing to pass economic screening under the RI Test. Under the Mid scenario, 82% of all savings result from electrifying existing delivered fuel space and water heating systems.

[18] To avoid double-counting, new construction heating electrification is not considered in this model as it is implicitly captured in new construction measures within the EE measures.

Figure E-17. Incremental Lifetime HE Fuel Savings by Year (All Fuels; 2021-26; All Scenarios)



Note: Program savings only represent natural gas and delivered fuel savings and do not include net increases in electricity consumption resulting from heating electrification.

In terms of electric impacts, heating electrification could increase electricity consumption by 17 GWh (Low) to 284 GWh (Max) by 2026, which would increase forecasted electricity sales by 0.2% to 3.7%, respectively. These impacts are net of savings that will occur from the provision of more efficient space cooling from the installation of heat pumps for space heating.

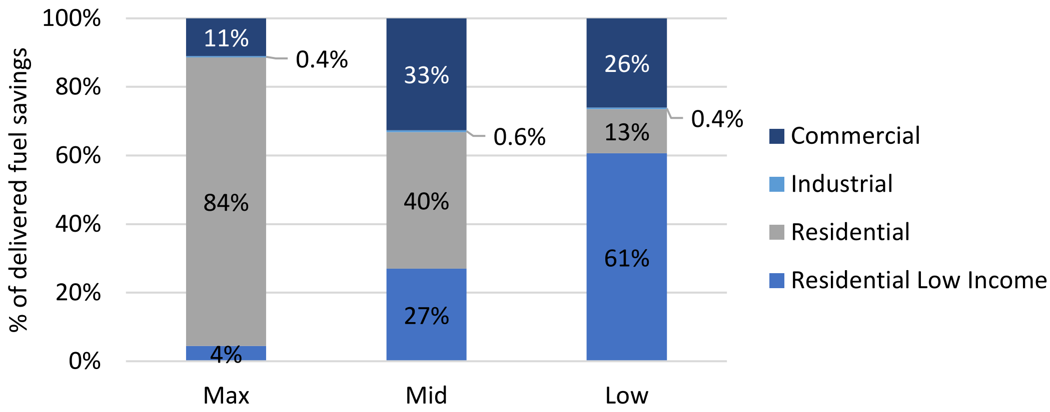
However, while heating electrification will increase electricity consumption, it will also result in a reduction in overall electric peak demand in Rhode Island as the study assumes the majority of heat pumps adopted for space heating electrification will also provide more efficient space cooling for most customers and Rhode Island is a summer peaking system. By 2026, heating electrification could decrease peak demand by 0.7 MW (Low) to 12.8 MW (Max) resulting in an overall reduction in peak demand of 0.04% to 0.7%, respectively. [19]

Program Savings by Market Sector

The bulk of fuel savings come from the residential and residential low-income sectors across all scenarios as shown in Figure E-18. However, under the Low scenario, most savings come from the residential low-income sector as adoption is driven by the assumption that this sector receives a 100% incentive. Limited adoption then occurs in the remaining sectors that receive a 25% incentive. However, as incentives increase for the other sectors in the Mid and Max scenarios, the relative proportion of fuel savings from the residential low-income shrink. Under the Max scenario, most savings come from the residential sector.

[19] Peak demand reductions only occur for customers with existing lower efficiency air conditioners, or customers who are likely to adopt air conditioning during the study period. For customers without existing AC and that are unlikely to have naturally adopted AC during the study period, heating electrification results in an increase in peak demand. In Rhode Island, most customers have existing AC, thus resulting in overall peak demand reductions from heating electrification.

Figure E-18. Proportion of HE Savings by Sector (Average Incremental Lifetime Fuel Savings)

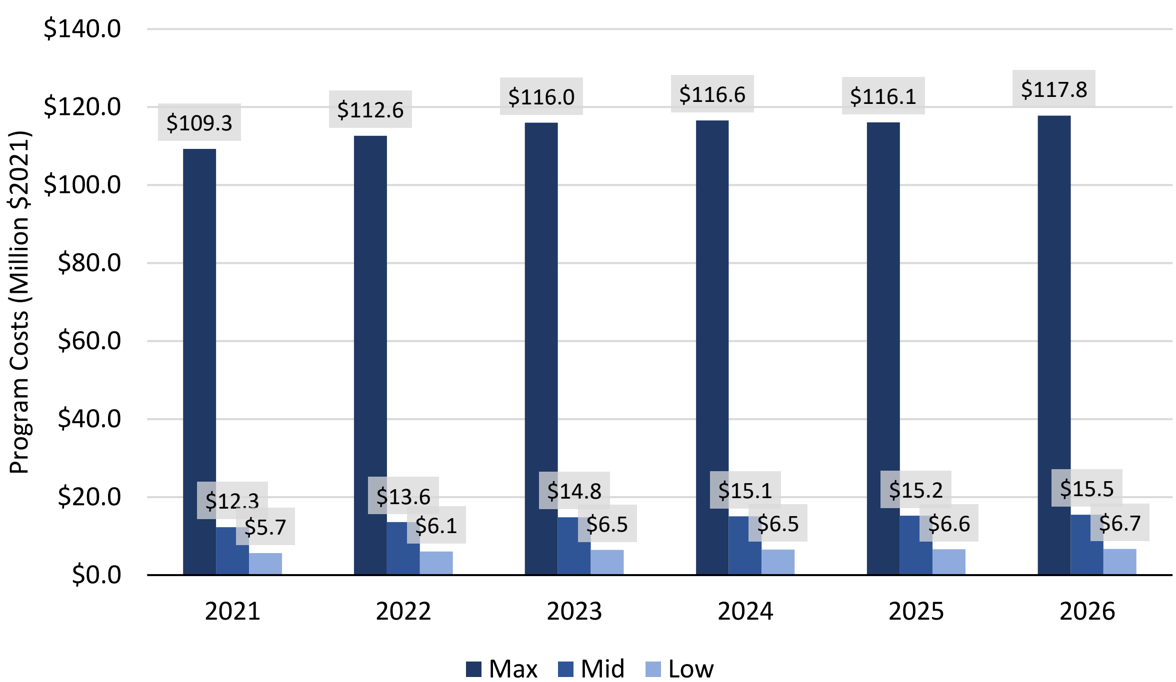


E.5.2 Portfolio Metrics

Program Costs

The study estimates that HE program costs will range between an average of $6.3 to $14.4 million under the Low and Mid scenarios, respectively, slowly increasing year-over-year as shown in Figure E-19. Under the Max scenario, estimated costs will average $115 million per year. This significant jump in estimated costs coincides with the large increase in heat pump adoption observed between the Mid and Max scenarios as previously discussed.

Figure E-19. HE Program Costs by Year (2021-26; All Scenarios)



Program Benefits

In all scenarios, electrification creates significant benefits to rate payers, customers, and society at large. Based on the RI Test, average net benefits generated each year range from $15 to $40 million under the Low and Mid scenarios, respectively. This includes an average annual addition of $8 million (Low) to $23 million (Mid) to Rhode Island's state gross domestic product (GDP) each year as shown in Table E-6.

Table E-6. Summary of Net HE Benefits Generated Each Year (2021-26 Average; All Scenarios)

Benefit	Max	Mid	Low
Lifetime RI Test Net Benefits (2021$)	$225M	$40M	$15M
Economic Development Benefits (2021$)	*$144M*	*$23M*	*$8M*
Lifetime Customer Net Bill Savings (2021$)	$59M	$13M	$7M
GHG Emission Reductions (tCO_2)	23,000	4,000	2,000

Note: Lifetime RI Test Net Benefits include Economic Development Benefits

As also presented in Table E-6, lifetime customer bill savings (e.g. reduction in gas or delivered fuel costs net of electricity cost increases) generated each year range from $6.7 million to $12.7 million under the Low and Mid scenarios, respectively, while GHG emission reductions range from 2,000 to 4,000 short tons of carbon-dioxide equivalent (tCO_2e) each year.[20, 21] Benefits are significantly larger under the Max scenario, which corresponds to the increased amount of heat pump adoption under this scenario.

E.5.3 Key Takeaways

Electrifying oil and propane-based systems offers the bulk of the economic opportunity for heating electrification. The high costs of oil and propane result in greater benefits that outweigh the cost of heat pump system installation and the associated electricity consumption. For most applications, electrifying natural gas-based systems does not pass economic screening.

For residential customers, large incentives are needed if significant market transformation is to be achieved. Compared to the increase in savings between the Low and Mid scenarios where incentives are increased from 25% to 50%, there is a much more significant increase in achievable fuel savings between the Mid and Max scenarios where incentives are increased from 50% to 100% of incremental costs. This suggests that up-front incentives in excess of 50% of the incremental cost of heat pump space heating systems are needed to drive large numbers of residential customers to electrify their heating systems.

Heating electrification creates significant net benefits for Rhode Island. The benefits from avoided fuel consumption and decreasing electric peak demand will far outweigh the costs of increased electricity consumption. The greater efficiency of heat pumps relative to fossil-fuel based systems results in the reduction of overall net customer energy consumption, and the addition of heat pumps for space heating will provide more efficiency space cooling to Rhode Island homes and businesses as well.

[20] Lifetime customer net bill savings are calculated by summing the annual bill savings over the effective lifetime of the measure and subtracting the portion of the measure's incremental cost paid by the customer (e.g. the customer pays 70% of the incremental cost when the utility offers a 30% incentive).
[21] Emission reductions are estimated using emission factors from the *Avoided Energy Supply Components (AESC) in New England: 2018* report. See Appendix F for more details.

E.6 Customer-Sited Solar PV

The PV module assesses the technical, economic, and achievable potential for customer-sited rooftop solar systems in Rhode Island during the study period as well as a forecast of storage-paired solar deployment in Rhode Island. Additionally, a meta-review of value of solar studies is conducted to provide a benchmark for the value that distributed solar adoption brings to the grid.

To explore the adoption of customer-sited solar PV in Rhode Island, the study models the impact of three scenarios that reflect different market and policy conditions related to the Renewable Energy Growth (REG) Program, the Renewable Energy Fund (REF) Incentives and PV system costs as highlighted in Figure E-20. Given that existing program support for solar PV in Rhode Island is significant, existing programs are modeled as the Mid scenario ("Base Case") with the Low and Max scenarios featuring reduced and more aggressive programs, respectively.

Figure E-20. Customer-Sited Solar PV Program Scenario Descriptions

Low

Reduced policy support for solar deployment and unfavorable market conditions after the phase-out of Federal Investment Tax Credit (ITC).
- REG program with constrained allocation
- Net-Metering with no upfront incentives
- High system costs post ITC phase-out

Mid

Business-as-usual policy support and market conditions for solar in Rhode Island that maintains the trajectory of current programs
- REG program with existing allocation
- Net-Metering with BAU incentives levels (stepped-down)
- BAU system costs post ITC phase-out

Max

More aggressive policy support and favorable market conditions for solar deployment in Rhode Island to counteract the impacts of the phase-out of the ITC.
- REG program with no allocation caps
- Net-Metering with BAU incentives (stepped-down gradually to mitigate ITC Phase-out)
- Low PV costs post ITC phase-out

E.6.1 Technical and Economic Potential

The theoretical maximum technical potential for rooftop solar PV in Rhode Island is calculated using data on the number of suitable sites, average system sizes, and energy generation potential for a typical system in each study segment. This estimate is then benchmarked and adjusted using results from additional sources that have quantified solar deployment potential using granular geospatial analyses. The analysis estimates approximately 4 GW of potential customer-sited solar capacity, corresponding to 4.7 TWh of annual electricity production. Nearly 60% of the identified technical potential is estimated to be in the commercial sector, with the remaining being residential and limited potential in the industrial sector. Using the RI Test, all technically feasible solar deployment is found to be cost-effective.[22]

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[22] For a full description of the costs and benefits included in the RI Test, please see the Attachment 4 - 2020 Rhode Island Test Description as filed with National Grid's 2020 EEPP (Docket No. 4979) accessible at: http://www.ripuc.ri.gov/eventsactions/docket/4979-NGrid-EEPP2020%20(10-15-19).pdf. The study does not

E.6.2 Achievable Potential

Base Case

Under the Base Case (Mid scenario), 15,300 new customer-sited solar systems, corresponding to 233 MW of solar capacity, are forecasted to be installed in Rhode Island over the study period. This forecasted adoption will contribute to 306 GWh of energy savings in 2026 (i.e. reduction in energy sales/consumption in that year) corresponding to approximately 3.9% of forecasted electricity sales during the same period as well as a 63 MW reduction in peak demand in the same period.

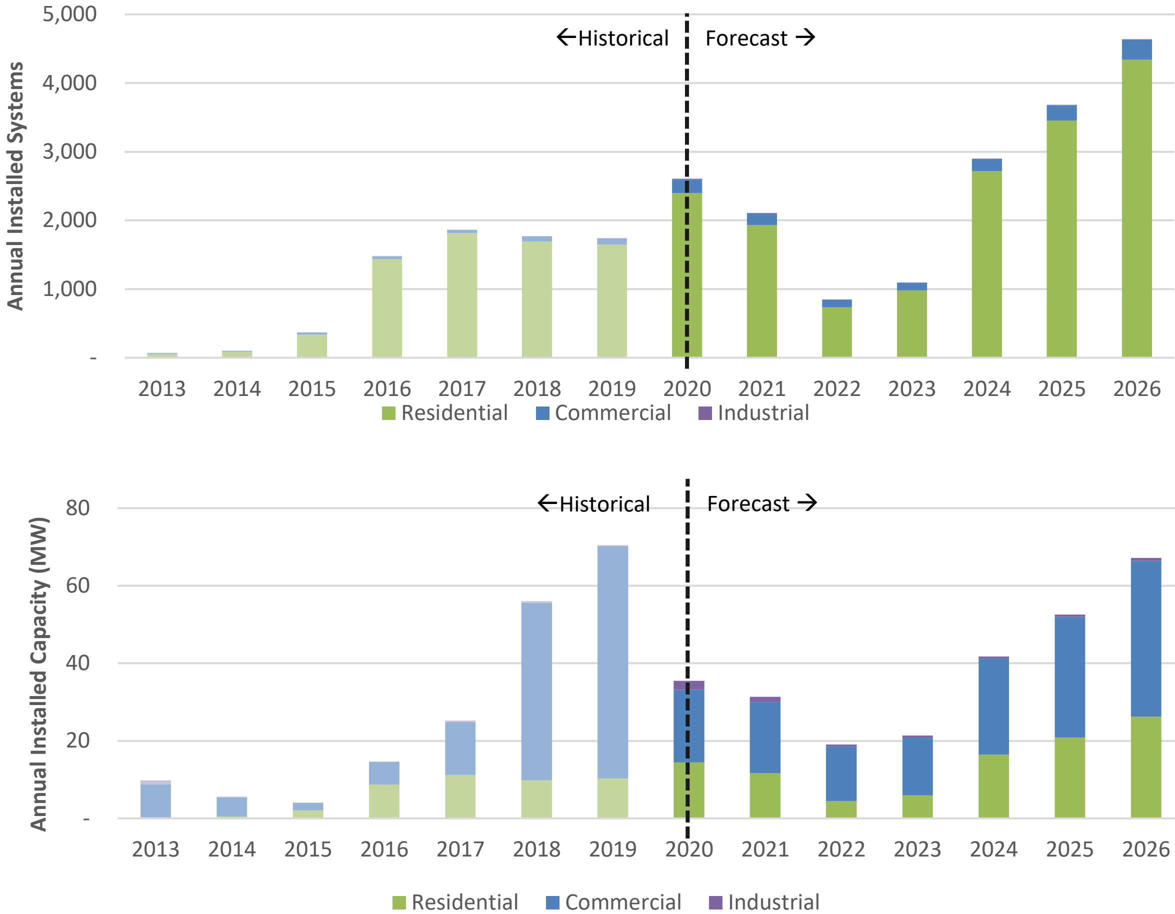
The majority of the installed systems (93%) are forecasted to be residential, however residential installs will only represent 37% of total installed capacity due to the larger sizes of commercial systems.

Overall, **the market is expected to slow down in the short-term due to the phase-out of the Federal ITC, with** a notable drop in solar uptake is observed in 2022 and 2023. The impacts on the ITC phase-out are expected to be more pronounced in the residential sector relative to the non-residential sector, due to the continuing 10% incentive for commercial applications. By 2024, the market is expected to pick up and return to historical deployment levels in terms of number of solar PV systems.

However, despite an increase in the number of systems installed in 2021 and in later years of the study (2024 – 2026) relative to historical uptake**, forecasted annual installed capacity (MW) is estimated to be below historical levels over most of the study period** as shown in Figure E-21. This is a result of a reduction in average system sizes over time in the commercial sector as increased adoption by smaller mass-market commercial customers results in smaller system sizes compared to those installed by early adopters and larger commercial customers.

consider the feedback between solar adoption and avoided costs. Such an analysis was not within the scope of the study.

Figure E-21. Historical and Forecasted Annual Installations and Capacity (Mid Scenario)



The results under the Base Case also highlight increasing interest in NEM over the study period, in-line with observed trends over the past 3 years. While nearly 60% of new solar installations in 2018 were under the REG Program, the share of REG is forecasted to decrease to 25% of new annual installed systems by 2026 due to the more favorable economics under NEM for potential adopters.

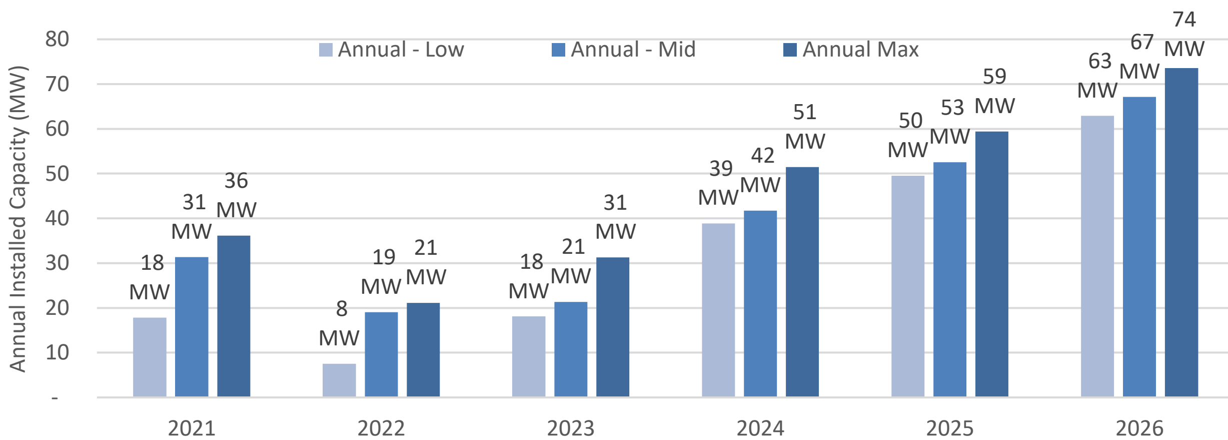
Low and Max Scenarios

To assess how different market and policy conditions could impact solar adoption in Rhode Island, two additional achievable potential scenarios (Low and Max) are modeled. Figure E-22 presents the forecasted annual customer-sited solar PV capacity additions for each scenario. The results highlight that more aggressive policy and market actions to mitigate the impacts of ITC could increase total installed capacity during the study period by 18% (273 MW relative to 233 MW under base case). Conversely, reduced policy support and high PV costs could reduce market potential by 19% (195 MW relative to 233 MW under base case).

Under the Low scenario, the reduced policy support for customer-sited solar in the form of cancellation of the REF program rebates and more constrained REG allocation caps will result in a sharp drop in adoption in the near-term (i.e. 2021 and 2023). In the longer term (2024 – 2026), natural un-incented market demand for solar will still increase significantly over the study period.

Under the Max scenario, a more moderate decline of incentives coupled with reductions in PV system costs can counteract the impacts of the ITC phase-out to some extent in the near-term (particularly in the residential sector) and maintain market growth in the latter years of the study. On the other hand, increases in REG caps are unlikely to result in significant changes to the market forecast, as the business case for NEM becomes more advantageous for customers and allocation caps are not met.

Figure E-22. Forecasted Annual Customer-Sited Solar PV Capacity Additions (All Scenarios)



Program Costs and Benefits

Considering the financial value of customer net metering and bill credits, incentive costs, and program administration costs, the study estimates program costs and committed spending as presented in Table E-7. Unlike upfront rebates and incentives paid out in a single program year, both NEM and REG provide customers with financial value (e.g. bill credits or net metering credits) for a defined period of time. For this reason, the study estimates program committed spending as the net present value (NPV) of customer bill credits made under both programs over the lifetime of the contracts in order to provide a full assessment of committed program spending[23,24].

Considering the benefits and costs of the forecasted customer-sited solar uptake under the three scenarios using the RI Test highlights the generation of average lifetime net benefits of $68 - $82M each year over the study period.[25]

[23] Net metering credit value is based on the estimated financial value to participating customers from offsetting their electricity loads and receiving credits for production exported to the grid.
[24] REG bill credit value includes the estimated bill credits issued to participating customers during their REG contract lifetime as well as bill credits issued after the end of their REG contracts assuming customers are compensated at retail rates.
[25] For a full description of the costs and benefits included in the RI Test, please see the Attachment 4 - 2020 Rhode Island Test Description as filed with National Grid's 2020 EEPP (Docket No. 4979) accessible at: http://www.ripuc.ri.gov/eventsactions/docket/4979-NGrid-EEPP2020%20(10-15-19).pdf

Table E-7. Annual Customer-Sited Solar Program Costs and Committed Spending (All Scenarios)

Scenario	Program	2021	2022	2023	2024	2025	2026	Average	Total
Low	REG	$32M	$9M	$30M	$53M	$45M	$42M	**$35M**	**$212M**
	NEM[26]	$92M	$37M	$88M	$214M	$297M	$404M	**$189M**	**$1,132M**
	Total	**$124M**	**$47M**	**$119M**	**$267M**	**$341M**	**$446M**	**$224M**	**$1,344M**
Mid	REG	$54M	$27M	$42M	$72M	$78M	$76M	**$58M**	**$349M**
	NEM +REF	$195M	$109M	$104M	$209M	$276M	$377M	**$211M**	**$1,269M**
	Total	**$249M**	**$136M**	**$147M**	**$280M**	**$354M**	**$453M**	**$270M**	**$1,617M**
Max	REG	$65M	$34M	$55M	$93M	$98M	$115M	**$76M**	**$459M**
	NEM +REF	$203M	$115M	$161M	$240M	$287M	$343M	**$225M**	**$1,348M**
	Total	**$268M**	**$148M**	**$215M**	**$333M**	**$385M**	**$458M**	**$301M**	**$1,807M**

Note: Values presented here include upfront incentive payments, administrative costs, and the NPV of REG bill credits and net metering credits dispersed to customers over a defined period of time.

E.6.3 Storage-Paired Solar Uptake

To assess the portion of solar uptake in Rhode Island that will be storage-paired over the study period, the study models the economics of standalone and storage-paired systems considering both the incremental benefits and costs to customers. Overall, the analysis shows a relatively limited business case for storage deployment in Rhode Island during the study period, with nearly 500 systems forecasted to be installed during the study period (i.e. between 2021 and 2026) under the base case with a total capacity of 8.8 MW (17.6 MWh).

E.6.4 Key Takeaways

195 MW (Low) to 273 MW (Max) of customer-sited solar capacity are forecasted to be deployed in Rhode Island over the study period. Specifically, the achievable market potential will highly depend on policy and market response after the ITC phase-out. The forecasted adoption will bring between 256 GWh (Low) and 358 GWh (Max) of cumulative energy savings from customer-sited solar penetration by 2026 as well as up to 72 MW (Max) in peak demand reductions. While the majority of customer-sited solar installations are expected to be in the residential sector, the non-residential installs dominate the market in terms of installed capacity due to the larger installation sizes.

Limited potential for the uptake of storage-paired solar in Rhode Island is forecasted over the study period due to the unfavourable economics. This is primarily the case in the residential sector, however higher uptake is forecasted in the commercial sector due to the benefits of peak demand charge reductions.

A meta-review of value of solar studies highlights the multitude of benefits distributed solar brings utilities, the grid and society, and shows a range of value estimates from 4 to 36 cents per kWh reflecting jurisdictional contexts as well as methodological differences across the studies. Additionally, the review shows that the majority of these benefits are considered and quantified in the RI Test.

[26] The REF program is assumed to be discontinued in the Low scenario.

1 Introduction

1.1 Study Overview

This report presents the results of the Rhode Island Market Potential Study (MPS). The MPS includes five modules covering the following savings streams:

- Energy efficiency (EE),
- Electric demand response (DR),
- Combined heat and power (CHP),
- Heating electrification (HE), and
- Customer-sited rooftop solar photovoltaic (PV) generation.

The MPS covers the six-year period between calendar years 2021 to 2026 and includes electricity, natural gas, oil, and propane energy savings; passive electric demand reduction savings and active demand response savings; and the costs and benefits associated with these savings.

The study covers the entire State of Rhode Island, which is predominantly served by National Grid for electric and natural gas distribution service. Therefore, the primary focus of this study and the majority of results presented within this report apply solely to National Grid's territory and customers. However, there are two other small electric utilities in Rhode Island – Pascoag Utility District (PUD) and Block Island Power. Where appropriate, results are also presented for these utilities and are clearly identified as applying to these utilities. When results, figures, and tables do not indicate the inclusion of results for either PUD or Block Island Power, the reader should assume the results only apply to National Grid's territory and customers.

1.1.1 Uses for the MPS

The MPS is a high-level assessment of electric, natural gas, and delivered fuel savings opportunities in the State of Rhode Island over the next six years. The main purpose of this study is to quantify the cost-effective savings opportunities for energy efficiency, electric demand response, combined heat and power, heating electrification, and customer-sited rooftop solar photovoltaic generation. In addition to this objective, the MPS can also support:

- Resource planning
- Program planning
- State policy and strategies

While the MPS provides granular information such as savings for specific measures in specific building segments, the study is not a program design document meant to accurately forecast and optimize savings and spending through utility programs in a given future year. The MPS is meant to quantify the total potential opportunities that exist under specific parameters as defined under each scenario.

1.1.2 COVID-19

COVID-19

The MPS was conducted in the first quarter of 2020 – i.e prior to the onset of the COVID-19 pandemic. Accordingly, **the study does not consider the implications COVID-19 will have on achievable savings potentials.**

Directionally, COVID-19 is likely to place *downward pressure* on achievable *incremental* savings potential. At the time of this report's writing, widespread economic lockdowns and social distancing orders were still in effect in Rhode Island with uncertainty on when they will be relaxed. Additionally, the lasting economic impacts of COVID-19 are still unclear but are likely to result in a significant economic slowdown. Both economic slowdowns and new social distancing practices can serve to increase barriers for efficiency programs.

In addition to this downward pressure, the impacts of COVID-19 could also *shift* achievable potential and the relative economics of savings opportunities among measures, market segments, fuels, and end-uses due to factors such as:

- **Shifting energy use patterns,** e.g. as more people work from their homes, energy savings opportunities may shift somewhat from office buildings to residential, and peak demand reduction opportunities may change as peaks themselves shift in time and end-uses,
- **Shifting customer demographics and behavior,** e.g. higher incentives may be needed to account for a growth in low and moderate income customers (and reduced disposable income), small business owners with depleted cash reserves or greater debt, and greater risk aversion across the board, and
- **Changing relative fuel costs,** e.g. lower cost of delivered fuels could reduce the customer value proposition of electrification, while lower power supply costs could increase the value proposition for utilities.

These and other potential changes in savings opportunities could require a shift both in how programs are designed, and where program resources are directed in order to maximize program impacts and cost-effectiveness.

At the time of writing, however, neither the shape of the anticipated economic recovery nor the permanence of certain economic and social changes are predictable with any degree of confidence. As a result, the extent and distribution of COVID-19's impacts over the full six-year study horizon are equally uncertain. We therefore caution against coming to hasty conclusions and encourage further analysis to understand the possible implications of the pandemic for demand-side energy resource programs in Rhode Island.

1.2 Data Sources and Uses

The MPS leverages a pool of Rhode Island specific data to populate the models used to estimate market potential. Where Rhode Island specific data is not available or insufficient, data from nearby jurisdictions is leveraged to fill gaps and produce a more robust representation of market parameters in the state. Table 1-1 provides an overview of the key data sources used in the study. A more detailed description of the sources, inputs, and assumptions can be found in Appendix F.

Table 1-1. Study Data Sources and Uses

Data source	Application in study
National Grid customer data	Customer data is used to determine the number of customers in each market segment.
Rhode Island baseline survey data	Recent baseline survey studies conducted in Rhode Island are used to establish equipment penetration and saturations in the model for select end-uses.
National Grid 2020 EE Plan Excel workbook	A detailed measure-level workbook accompanying National Grid's 2020 EE Plan is used to derive avoided cost and other economic inputs as well as to benchmark results.
National Grid program data	Historical program data is used to characterize programs for model input (e.g. incentive levels, administrative costs) and used to benchmark results.
National Grid's interconnection data	Historical solar PV adoption is used to calibrate our solar adoption model to the Rhode Island market
National Grid's historical load	Historical hourly load data from the start of 2014 up to the end of April 2019 was used to assess peak demand and evaluate demand response potential.
Renewable Energy Fund (REF) program database and annual reports	Program data used to estimate historical adoption of behind the meter PV by segment as well as historical system costs, system sizes and program costs.
Public Utilities Commission Renewable Energy Growth (RE Growth) dockets	Submissions from National Grid, the Distributed Generation Board and other stakeholders in regulatory dockets submitted in annual RE Growth proceedings are used to identify REG PV program incentive levels (price caps), allocation caps, program costs and other ancillary market and measure data (e.g. Rhode Island specific system costs) required for the study.
U.S. DOE Building Archetypes	Buildings archetypes, adjusted for Rhodes Island climate and consumption, were used to provide end-use breakdown and for quality control purposes.
Dunsky's Market Archetype	Where Rhode Island specific baseline data is not available (or was based on a low number of observations), baseline data from neighboring jurisdictions in the Northeast United States is leveraged and adjusted for Rhode Island specific attributes wherever possible.

1.3 Market Segmentation

Based on an analysis of anonymized National Grid customer metering data, the MPS segments National Grid's customer base into four sectors with the residential sector split into two building segments and the commercial sector split into nine as presented in Table 1-2.

Table 1-2. Study Market Sectors and Segments

Sector / Segment	Number of Customers
Residential	364,494
Single Family	*318,737*
Multi-Family[27]	*45,757*
Residential Low Income	29,883
Commercial	38,821
Office	*14,761*
Retail	*7,028*
Food Service	*3,321*
Healthcare & Hospitals	*3,308*
Campus & Education	*1,472*
Warehouse	*1,405*
Lodging	*3,321*
Other Commercial	*2,909*
Food Sales	*1,296*
Industrial	2,373

1.4 Achievable Scenarios

As is standard practice in potential studies, the study assesses potential at the technical, economic, and program achievable levels. For each module, the study explores three program achievable scenarios in order to determine how various levels of incentives and market barrier-reduction activities can impact achievable savings. In general, achievable potential is the focus of this analysis.

Figure 1-1. Figure 1-1 provides general descriptions for each achievable scenario. More detailed descriptions are provided for each module in their respective chapters.

[27] The multi-family population count represents individual residential units within multi-family buildings.

Figure 1-1. Achievable Program Scenario Descriptions

Low	Applies incentives and enabling activities in line with National Grid's 2020 Energy Efficiency Plan to simulate savings under **business as usual.**
Mid	Increases incentives and enabling activities **above and beyond** levels within National Grid's 2020 Energy Efficiency Plan.
Max	Completely eliminates customer costs to further reduce customer adoption barriers to estimate **maximum achievable potential.**

Enabling Activities

To optimize achievable potential savings, programs must go beyond incentive strategies to address other non-economic barriers to customer participation. Barrier reductions can be achieved through enabling activities that streamline program participation including but not limited to:

- Direct install programs
- Contractor training and support
- Upstream programs
- Targeted marketing
- Building and home energy labeling requirements
- Financing programs

The program scenarios assessed in this study capture the impact of current enabling strategies applied by National Grid by calibrating the Low scenario achievable potentials to current portfolio savings. The potential impact of investing further in enabling strategies is assessed under the Mid program scenario, where additional barrier level reductions are applied over and above the Low scenario where possible. While the potential study does not identify the specific enabling strategies engaged or the associated barriers addressed, the results are intended to provide a quantitative assessment of additional savings that can be unlocked through enabling strategies. More detail on program characterization and enabling activities can be found in Appendix F.

1.5 Sensitivities

The study tests various modules against multiple sensitivity scenarios as summarized in Table 1-3.

Table 1-3. Sensitivity Scenario Descriptions

Sensitivity Scenario	Baseline	Sensitivity
Retail Rates	Retail electricity, natural gas, and delivered fuel rates are forecasted in line with current best information.	Forecasted retail electricity, natural gas, and delivered fuel rates are increased/decreased by 25% impacting bill savings associated measures that impact energy consumption.
EISA	Savings from specialty and reflector bulbs are available to efficiency programs for the first two years of the study period.	All savings from specialty and reflector bulbs are removed for the entire study period to simulate the enforcement of the federal Energy Independence and Security Act (EISA) of 2007 backstop provision beginning in 2020. This federal act would mandate efficiency levels for specialty and reflector bulbs that would prevent an EE program administrator from claiming incremental energy savings from their installation.
AMF	Advanced metering functionality (AMF) is not available during the study period.	Advanced metering functionality (AMF) is widely deployed by 2024 impacting data availability for demand response and time-of-use rates.

1.5.1 Retail Rates

For the retail rate sensitivity, baseline retail rates for electricity, natural gas, oil, and propane are adjusted upwards and downwards by 25% for the entire model evaluation period, which extends past the study period to calculate bill savings that occur after 2026 for long-lived measures. The sensitivity is separately tested for electric rates and fuel rates.

1.5.2 EISA

At the time of this study, federal efficiency standards for lighting were in flux due to uncertainty regarding the triggering of the "backstop" mechanism for specialty A-lamp lighting in the 2007 Energy Independence and Security Act (EISA). To understand the impact of this uncertainty, the study incorporates two scenarios regarding specialty and reflector light bulbs:

- The **baseline scenario** assumes the backstop provision is delayed and/or the market naturally transforms beginning on January 1st, 2023 (halfway through the study period). Under this scenario, sub 45 lumen per watt reflector and speciality lamp sales end the year of compliance/transformation.
- The **alternative scenario** assumes the backstop provision begins in 2020 before the study period begins. Under this scenario, savings from reflectors and speciality lamp measures are not included.

Accordingly, sensitivities around the enforcement of EISA only impact electric efficiency savings in the first two years of the study.

1.5.3 AMF

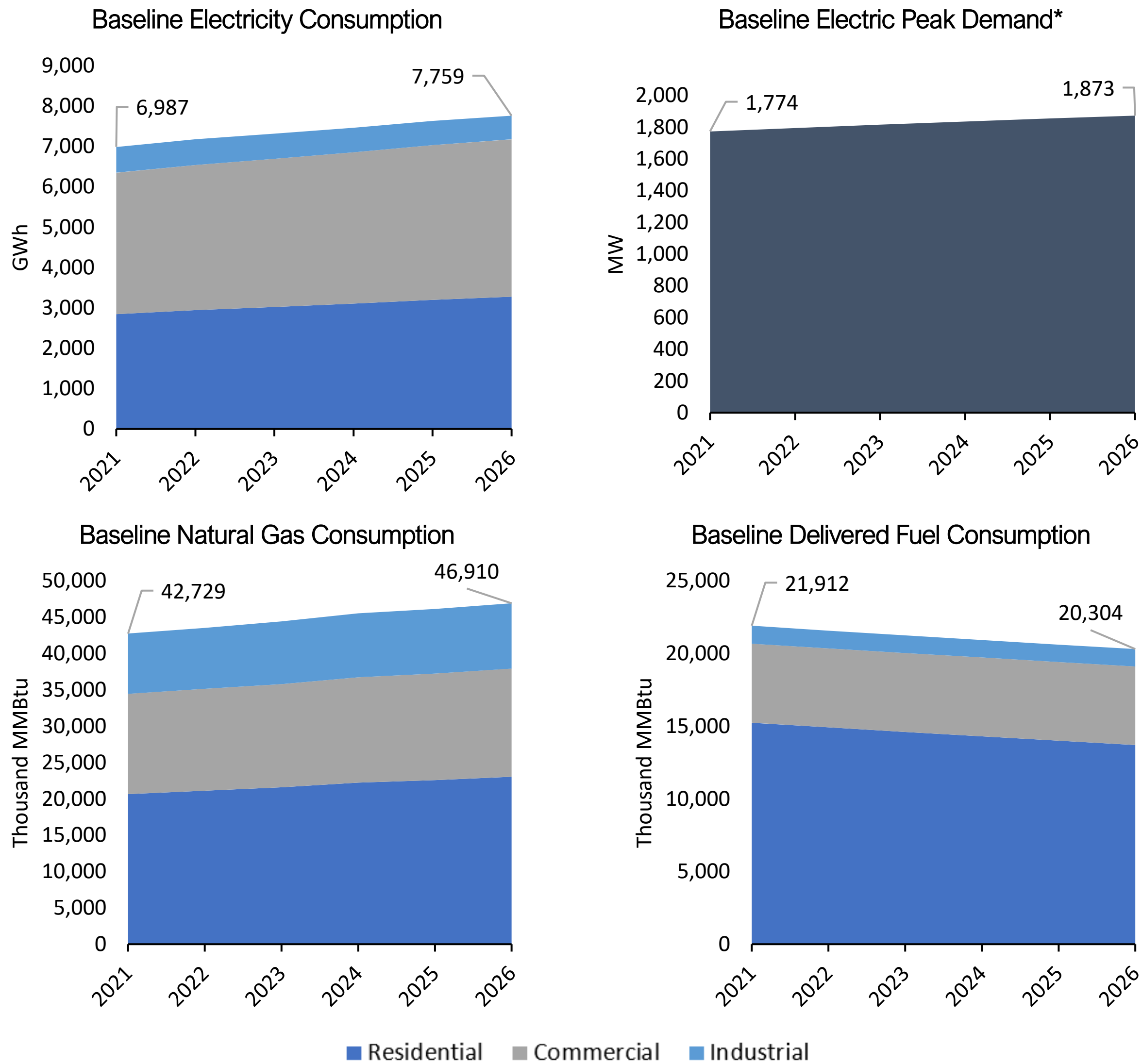
The deployment of advanced metering functionality (AMF) can have significant impacts on demand response potential. Demand response potential is tested against the availability of AMF beginning in 2024. It is also tested against the implementation of time-of-use rates, which are enabled by AMF.

1.6 Baseline Energy and Demand Forecasts

To help discern the impact of the various measures analyzed in the MPS on overall energy consumption and demand in Rhode Island, the study establishes baseline energy and demand forecasts for the study period. Electric and natural gas consumption and electric demand forecasts provided by National Grid and delivered fuel forecasts developed by the Energy Information Agency were adjusted to remove the projected impacts of existing and planned energy efficiency programs and customer-sited solar adoption during the study period to avoid double counting impacts estimated throughout the MPS. A more detailed description of the approach used to derive these forecasts is included in Appendix F.

Figure 1-2 presents the adjusted baseline forecasts for each fuel type and electric peak demand. Electricity and natural gas consumption as well as electric peak demand are expected to increase over the study period at annualized rates between 1% and 2%, while delivered fuel consumption is expected to decline at an annualized rate of 1.5% – even in the absence of efficiency programming. These forecasts are used to illustrate the cumulative impacts of savings within each study module chapter as well as the aggregate combined impacts of each module in Chapter 7.

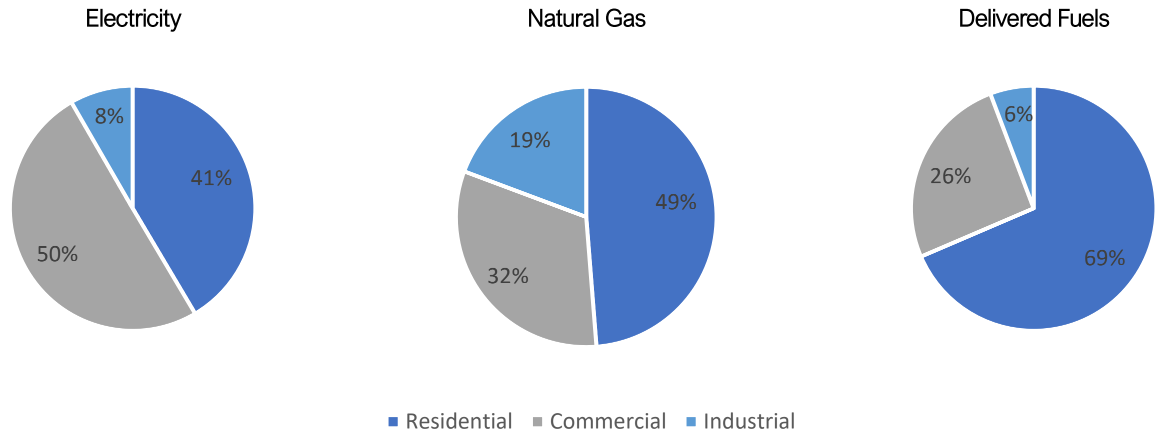
Figure 1-2. Baseline Energy and Peak Demand Forecasts



*Forecasted peak demand provided by National Grid was not disaggregated by sector.

As shown in Figure 1-3, electricity consumption is concentrated in the residential and commercial sectors with the commercial sector accounting for half of electricity consumption during the study period. Relative to electricity consumption, the industrial sector consumes a larger proportion of overall natural gas consumption in the state. Finally, delivered fuel consumption is concentrated in the residential sector, with nearly 70% of total consumption. The majority of delivered fuel consumption is oil – accounting for 96% of delivered fuel consumption with the remainder being propane.

Figure 1-3. Proportion of 2021-2026 Forecasted Energy Sales by Sector



1.7 Savings Terminology

This report expresses results in terms of *cumulative savings* and *program savings*.

Cumulative savings are a rolling sum of all new savings from measures that are incentivized by efficiency programs that will affect energy sales. Cumulative savings provide the total expected impact on energy sales and electric peak demand and are used to determine the impact of efficiency programs on long-term energy consumption and peak demand. Where applicable, cumulative savings are adjusted to account for mid-life baseline adjustments and the retirement of efficiency equipment that has reached the end of its effective useful life (EUL).

Program savings provide the level of savings from measures that are incentivized by efficiency programs *in a given year*. Efficiency targets and plans are generally expressed in terms of program savings – i.e. the amount of savings programs procure in a given year. Historically, Rhode Island has set efficiency targets and National Grid has developed efficiency plans in terms of **incremental annual savings.** Incremental annual savings are expressed in terms of savings achieved in the first year of all measures incentivized through efficiency programs. However, in March 2020 the EERMC adopted efficiency targets in terms of **incremental lifetime savings.** Incremental lifetime savings are expressed in terms of the savings expected over the entire useful lives of all measures incentivized through efficiency programs.

2 Energy Efficiency

2.1 Overview

The following chapter presents results for the energy efficiency (EE) module of the Rhode Island Market Potential Study (MPS). The EE module estimates energy savings for electric, natural gas, and delivered fuel (oil and propane) measures as well as peak demand savings (i.e. passive demand reductions) for electric measures. It does *not* include savings or consumption impacts from heating electrification (HE), combined heat and power (CHP), demand response (DR) or customer-sited solar, which are discussed in subsequent chapters.

The chapter first briefly summarizes key results, the approach used to estimate EE potential, and the program scenarios explored in the analysis. A full description of the methodology can be found in Appendix A. A more detailed analysis of results is then presented in the following order:

- **Program savings**. Savings are presented in terms of incremental lifetime savings achieved during the study period for each saving stream – electricity, natural gas, and delivered fuels. Where warranted, incremental annual savings are also presented for comparison purposes.
- **Portfolio metrics**. The benefits and costs of efficiency savings are presented at the portfolio-level.
- **Sensitivity analysis**. The impact of various sensitivities scenarios on program savings and portfolio metrics are presented.
- **System impacts**. Savings are presented in terms of *cumulative* savings to provide an assessment of system-level impacts of efficiency savings.

2.1.1 Summary of Results

Overall, the study finds that Rhode Island has the potential to capture a large portion of cost-effective efficiency savings over the study period that will generate significant benefits for the state.

For electric measures, the study estimates efficiency programs can procure an average of 1,261 GWh (Low) to 2,015 GWh (Max) of incremental lifetime savings each year during the study period. This represents between 47% (Low) to 73% (Max) of economic savings.[28] Under business-as-usual conditions (i.e. Low scenario), incremental lifetime savings will be below historical levels as savings from standard bulbs (A-Lamps) become no longer claimable for efficiency programs. However, similar levels of savings are achievable under the Mid scenario, and the Max scenario represents an opportunity to significantly increase savings above current levels.

[28] Economic savings are savings from measures that pass the Rhode Island Benefit Cost Test ("RI Test") as approved by the Rhode Island Public Utility Commission in Docket 4755 and in accordance with the Docket 4600 Benefit-Cost Framework.

For natural gas measures, the study estimates that efficiency programs can procure an average of 5,529 thousand MMBtu (Low) to 9,966 thousand MMBtu (Max) of incremental lifetime savings each year during the study period. This represents between 48% (Low) to 79% (Max) of economic savings. This result is higher than historical savings and suggests there is an increasing opportunity to for savings growth.

For delivered fuel measures, the study estimates that efficiency programs can procure an average of 1,940 thousand MMBtu (Low) to 3,803 thousand MMBtu (Max) of incremental lifetime savings in delivered fuels each year during the study period. This represents between 47% (Low) to 75% (Max) of economic savings.

Estimated program costs range from an average of $120 (Low) to $302 (Max) million per year. However, program savings will generate an average of $446 (Low) to $910 (Max) million net lifetime benefits from measures incentivized each year for Rhode Island.[29] The study estimates that efficiency measures have the potential to reduce Rhode Island's carbon footprint by 539,000 to 879,000 short tons of carbon-dioxide equivalent (tCO_2e) by 2026, which is roughly equivalent to removing 105,000 to 172,000 passenger vehicles from the road for a year.[30]

2.1.2 Approach

The market potential for EE is assessed using the Dunsky Energy Efficiency Potential (DEEP) model. DEEP employs a bottom-up modelling approach that assesses thousands of "measure-market" combinations, applying program impacts (e.g. incentives and enabling activities that reduce customer barriers) to assess energy savings potentials across multiple scenarios. Rather than estimating potentials based on the portion of each end-use that can be reduced by energy saving measures and strategies (often referred to as a "top-down" analysis), the DEEP's approach applies a highly granular calculation methodology to assess the energy savings opportunity for each measure-market segment opportunity in each year.

DEEP estimates interactive effect impacts for measures that may have material impacts on secondary fuel usage (e.g. the installation of LEDs leading to increased natural gas usage from space heating systems since LEDs produce less heat than incandescent or halogen bulbs). Interactive effect impacts are included within each fuel-specific savings stream (i.e. electric savings from measures that indirectly increase or decrease electricity consumption are accounted for under electric program savings). The interactive effect impacts can be found in Appendix G, which provides detailed results for measures at the end-use level for each savings stream.

A more detailed description of the methodology can be found in Appendix A.

[29] Net benefits are calculated based on the Rhode Island Benefit Cost Test ("RI Test") as approved by the Rhode Island Public Utility Commission in Docket 4755 and in accordance with the Docket 4600 Benefit-Cost Framework.
[30] Passenger vehicle estimate calculated using the EPA Greenhouse Gas Equivalencies Calculator accessible at: https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator

Benchmarking EE Results

To provide additional context to the study results, this chapter compares results to savings achieved by National Grid in 2019 and savings goals for 2020. National Grid's 2019 savings are taken from the 2019 Energy Efficiency Fourth Quarter Report, which provides draft efficiency savings achieved for the entire 2019 calendar year ("Draft 2019 Results").[31] National Grid's 2020 savings targets are taken from the Benefit-Cost Ratio Model Excel workbook that accompanied the 2020 Energy Efficiency Program Plan ("2020 EEPP") as filed by National Grid, which allowed for savings to be disaggregated by end-use to a certain degree.[32] To the greatest extent possible, benchmark savings metrics exclude savings attributable to CHP and HE measures to ensure consistent comparisons.

2.1.3 Program Scenarios

The EE module explores three achievable program scenarios as described in Figure 2-1.

Figure 2-1. EE Module Program Scenario Descriptions

Low	Applies incentives and enabling activities in line with National Grid's 2020 Energy Efficiency Plan to simulate **business as usual.**
Mid	Increases incentives and enabling activities **above and beyond** levels within National Grid's 2020 Energy Efficiency Plan.
Max	Completely eliminates customer costs to further reduce customer adoption barriers to estimate **maximum achievable potential.**

The Low scenario is designed to emulate savings that may be achieved under incentive levels and enabling activities indicative of current programs albeit with measures and technologies that may not be currently offered by existing programs. The Mid scenario increases average incentive levels to at least 75% of incremental costs for all programs and ramps up program enabling activities where feasible (see Chapter 1 for more information on program enabling activities). Finally, the Max scenario increases incentives to 100% of incremental costs so that customers do not pay any additional cost for efficient technologies while maintaining the same enabling activities assumed in the Mid scenario. For a more

[31] The 2019 Energy Efficiency Fourth Quarter Report was presented at the February EERMC meeting and is accessible at: http://rieermc.ri.gov/wp-content/uploads/2020/02/2019-ri-fourth-quarter-highlights-final-ri-puc.pdf. A final report for 2019 is scheduled to be filed with the RI PUC in May 2020 and may differ from the draft report referenced in this study.

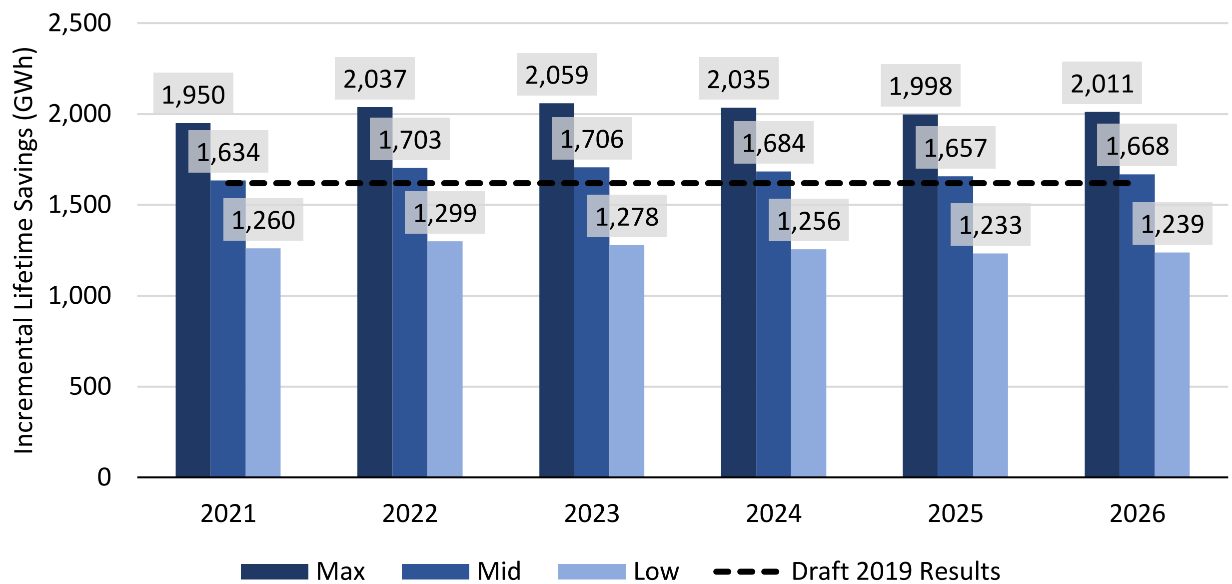
[32] National Grid's 2020 EEPP (Docket No. 4979) is accessible at: http://www.ripuc.ri.gov/eventsactions/docket/4979page.html. The Excel workbook used for this study is not publicly available.

complete description of program characterization and assumptions underlying each scenario, please see Appendix F.

2.2 Electric Program Savings

The study estimates that efficiency programs can procure an average of 1,261 GWh (Low) to 2,015 GWh (Max) of incremental lifetime savings each year during the study period. As shown in Figure 2-2, incremental lifetime savings remain relatively stable across the study period – fluctuating by less than 2% year-over-year – except for 2022 when savings increase by 3.0% (Low) to 4.5% (Max) from the prior year as savings increase from measures that are not significant components of existing efficiency programs and savings from speciality and reflector bulbs are still claimed by programs.

Figure 2-2. Electric Incremental Lifetime Savings by Year (2021-26; All Scenarios)



If measured in terms of incremental annual program savings, EE programs can procure between an average of 125 GWh (Low) to 184 GWh (Max) of savings each year between 2021 and 2026 (see Table 2-1 below). Between 2022 and 2023, annual incremental savings decline by between 7% (Max) to 10% (Low). This drop-off is primarily due to the elimination of savings attributable to specialty bulbs (i.e. reflectors, candelabras, and globes), which contribute 10% to 11% of incremental annual savings in 2021 and 2022 under the Mid scenario. In terms of incremental lifetime savings, however, savings only decline by 1.6% between 2022 and 2023 under the Low scenario and remain relatively unchanged under the Mid and Max scenarios. This difference is due to the following two factors:

- **The short persistence of specialty bulb savings reduces their impact on lifetime savings.** In the first two years of the study, speciality and reflector bulb measures produce significant incremental annual savings as there are many bulbs eligible for replacement each year prior to the assumed market transformation. However, while replacing baseline (e.g. halogen) specialty bulbs with high-efficient versions produces significant incremental annual savings, the study assumes these savings only persist for one to three years due to the short effective useful life of halogen bulbs (see Appendix F for a more detailed description of how the study treats bulb saving persistence). Thus, these measures have relatively low incremental lifetime savings.

- **Measures with longer lifetimes ramp-up to become increasingly important in the later years of the study.** While savings from specialty bulbs are removed from the market, the study assumes other measures are ramping up to their full achievable potential (see Appendix F for a list of measures where ramp rates are applied). These measures tend to have longer savings persistence than specialty bulb measures and thus produce greater lifetime savings on a per unit basis. Under the Mid and Max scenarios, the increase in savings from these measures more than makes up the loss of savings from specialty bulbs over the span of the study period.

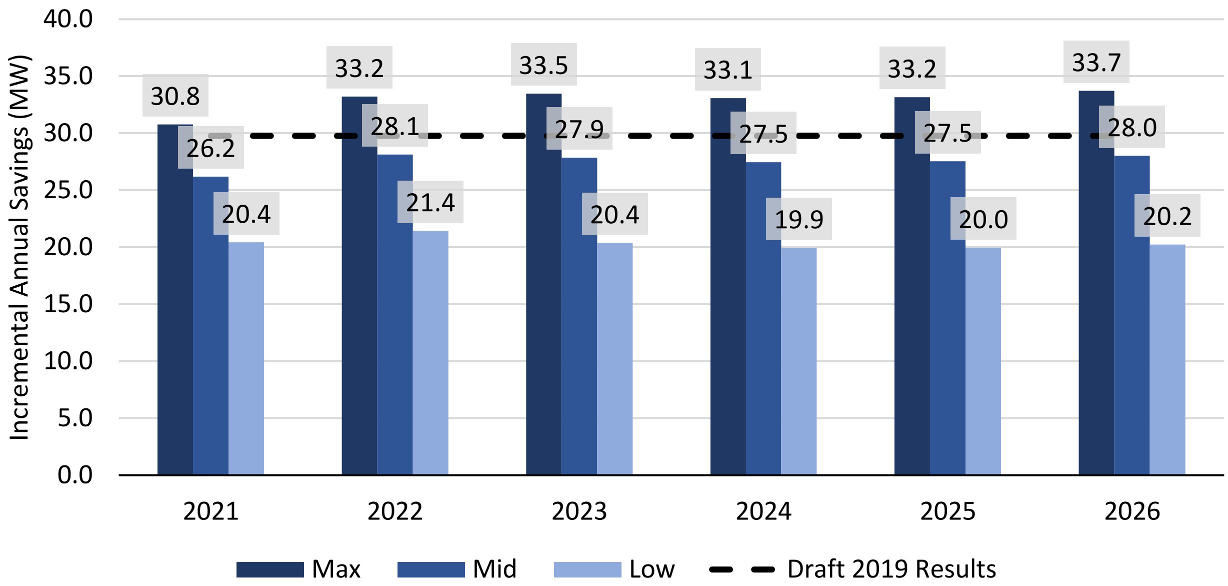
Compared to National Grid's Draft 2019 Results and 2020 EEPP, electric efficiency program savings under business-as-usual conditions (i.e. Low scenario) will be lower throughout the study period on an incremental lifetime and incremental annual basis due to the exclusion of lighting savings from standard bulbs (A-Lamps) – which are a significant component of savings in current programs – for the entire study period as the study assumes LEDs will become the new baseline technology for standard bulbs by 2021. However, the Mid scenario offers similar levels of savings particularly in terms of incremental lifetime savings, and the Max scenario represents an opportunity to significantly increase savings above current levels.

Table 2-1. Electric EE Incremental Lifetime Savings, Incremental Annual Savings, and Incremental Annual Savings as Percentage of Overall Sales by Year (All Scenarios)

Program Savings	Scenario	2021	2022	2023	2024	2025	2026	Average	Draft 2019 Results	2020 EEPP
Incremental Lifetime Savings (GWh)	Max	1,950	2,037	2,059	2,035	1,998	2,011	**2,015**	*1,619*	*1,474*
	Mid	1,634	1,703	1,706	1,684	1,657	1,668	**1,675**		
	Low	1,260	1,299	1,278	1,256	1,233	1,239	**1,261**		
Incremental Annual Savings (GWh)	Max	189	196	182	180	179	180	**184**	*190*	*176*
	Mid	164	170	156	154	153	154	**159**		
	Low	132	136	122	120	119	120	**125**		
% of Annual Sales	Max	2.7%	2.8%	2.6%	2.6%	2.6%	2.6%	**2.7%**	*2.8%*	*2.5%*
	Mid	2.4%	2.4%	2.2%	2.2%	2.2%	2.2%	**2.3%**		
	Low	1.9%	1.9%	1.7%	1.7%	1.7%	1.7%	**1.8%**		

In terms of passive demand reduction, incremental annual savings range from an average of 20.4 MW (Low) to 32.3 MW (Max) across the study period as shown in Figure 2-3. Relative to Draft 2019 Results (29.8 MW) and the 2020 EEPP (29.6 MW), passive demand reductions under the Low and Mid scenarios are lower, which is driven by the loss of demand savings from standard bulbs as claimed in current programs.

Figure 2-3. Electric Demand Incremental Annual Savings by Year (2021-26; All Scenarios)

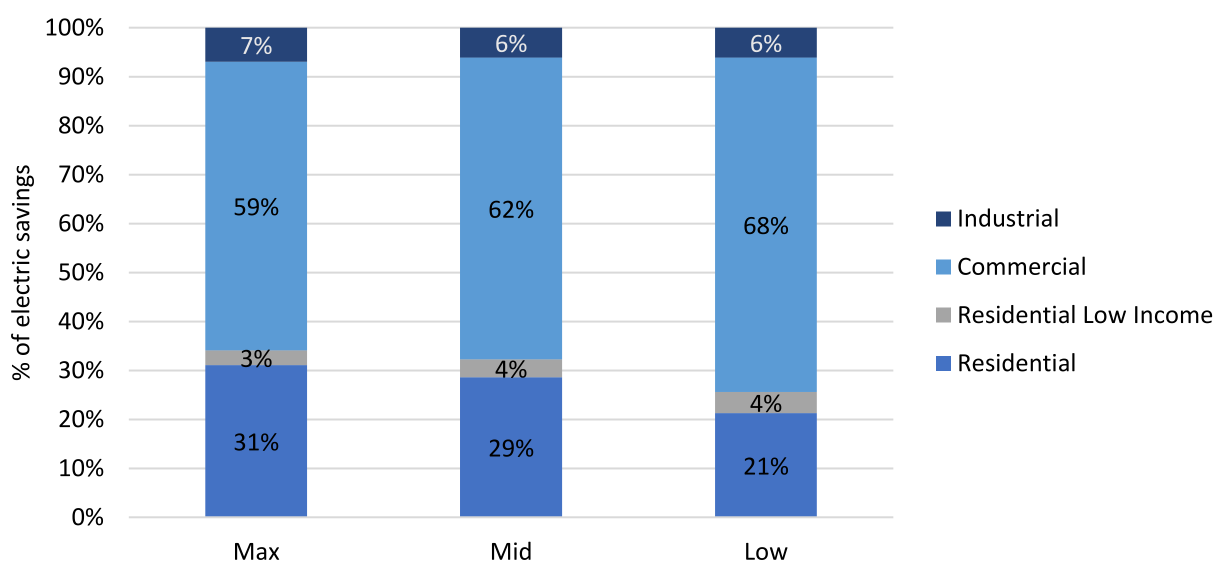


Note: The above figure represents passive demand reductions from EE measures and does not include active demand response.

2.2.1 Program Savings by Market Sector

The bulk of electric efficiency savings come from the commercial sector with approximately 68% of savings coming from the sector under the Low scenario even though commercial customers only account for roughly 50% of electricity consumption in Rhode Island. Under the Mid and Max scenarios, the commercial sector's relative proportion of the overall electric portfolio progressively declines compared to the Low scenario as shown in Figure 2-4.

Figure 2-4. Proportion of Electric EE Savings by Sector (2021-26 Average Incremental Lifetime Savings; All Scenarios)



While savings for each sector progressively increase under the Mid and Max scenarios (see Table 2-2), savings from the residential sector increase at a faster rate as . When compared to the Low scenario, savings from the residential sector increase by 79% and 134% under the Mid and Max scenarios, respectively. Conversely, commercial sector savings only increase by 20% and 38% under the Mid and Max scenarios, respectively. This result suggests the opportunity to increase savings by investing in new measures, higher incentives, and further enabling strategies is particularly pronounced in the residential sector – especially for measures that provide greater lifetime savings such as more efficient furnaces and boilers.

When the share of overall electric savings by sector is measured in terms of incremental annual savings, the commercial sector's share under the Low scenario is only 56%, which is more aligned with the sector's share of electric consumption, and declines only slightly under the Mid (53%) and Max (52%) scenarios. This further suggests that increased incentives and reduced barriers under the Mid and Max scenarios drive greater adoption of long-lived measures among residential customers.

Compared to National Grid's Draft 2019 Results and 2020 EEPP Plan, the study shows that it is possible to achieve savings in the study period at levels similar to historical years across nearly every sector under the Mid and Max scenarios – albeit with a different mix of measures than in prior years. The one exception is the residential low-income sector. As can be seen in Table 2-2, residential low-income electric savings do not surpass savings achieved in 2019 or planned for 2020. This may be attributable to multiple factors. First, there are fewer levers available to increase savings since incentives for these measures are already at 100% of incremental costs in existing programs and direct install approaches are often applied. And second, the study may be underestimating the population eligible to participate in low-income efficiency programs. As described in Appendix F, customer segmentation was conducted using anonymized National Grid customer data, and low-income customers were identified by customers on income-eligible rates. Income requirements for participating in National Grid's income eligible energy savings program are based on annual household income, and not necessarily rate classification.[33] There may be more National Grid customers that qualify for the income eligible saving program than are currently under income-eligible rates, which would result in undercounting this population in the study.

Table 2-2. Electric EE Savings by Sector (2021-2026 Average Incremental Lifetime Savings; All Scenarios)

<table>
<tr><th>Sector</th><th>Max</th><th>Mid</th><th>Low</th><th>Draft 2019 Results</th><th>2020 EEPP</th></tr>
<tr><td>Residential</td><td>626</td><td>479</td><td>268</td><td>451</td><td>354</td></tr>
<tr><td>Residential Low-Income</td><td>61</td><td>61</td><td>55</td><td>69</td><td>74</td></tr>
<tr><td>Commercial</td><td>1,188</td><td>1,033</td><td>860</td><td rowspan="2">1,099</td><td rowspan="2">1,047</td></tr>
<tr><td>Industrial</td><td>140</td><td>102</td><td>77</td></tr>
<tr><td>Total</td><td>2,015</td><td>1,675</td><td>1,261</td><td>1,619</td><td>1,474</td></tr>
</table>

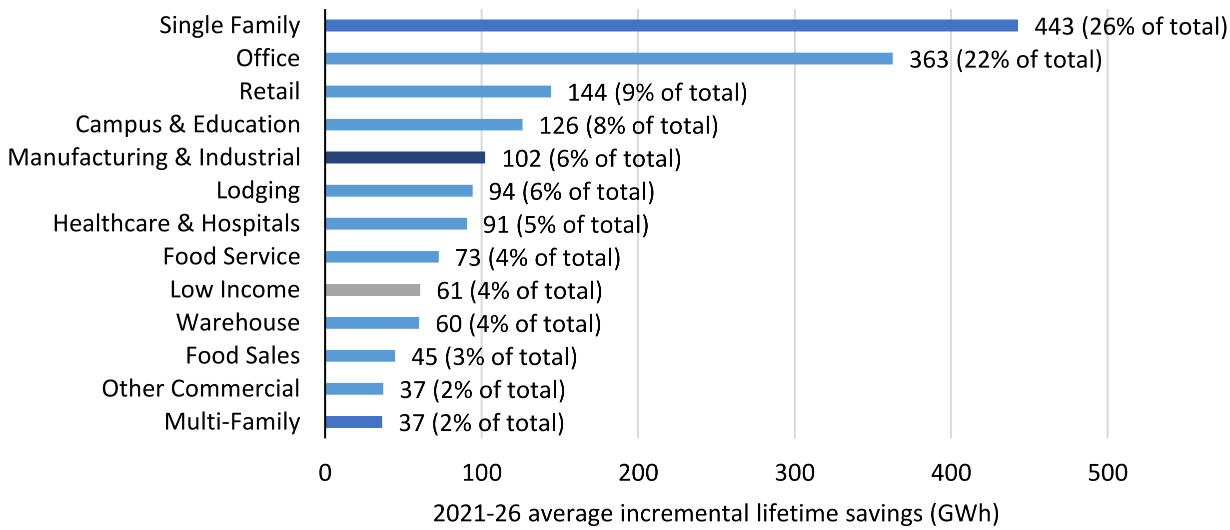
Note: Savings are not broken down by commercial and industrial sectors in 2019 Results and the 2020 Plan.
Units: GWh

At the segment level, the single family and office segments represent the bulk of electric EE savings. Under the Mid scenario, nearly half of all electric energy efficiency savings come from these two segments

[33] See: https://www.nationalgridus.com/RI-Home/Energy-Saving-Programs/Income-Eligible-Services

(see Figure 2-5). Retail, campus & education, and manufacturing & industrial round out the top five segments for electric EE savings.

Figure 2-5. Electric EE Savings by Segment (Average Incremental Lifetime Savings; Mid Scenario)



Block Island and Pascoag Utility District

Electric efficiency savings for the Block Island Utility District ("Block Island") and Pascoag Utility District (PUD) are estimated by scaling estimated savings for National Grid based on each utility's relative residential and C&I customer count. A full description of this scaling process is provided in Appendix F.

As shown in Table 2-3 and Table 2-4, the study estimates there is an additional 29.5 (Low) to 44.3 (Max) GWh of incremental lifetime savings per year in the Block Island and PUD jurisdictions. PUD has greater potential due to a greater number of residential customers relative to Block Island. Both utilities have similar amounts of commercial and industrial potential due to similar numbers of these customers in their territories. Overall, the combined estimated savings potential for PUD and Block Island is between 2.2% (Max) and 2.3% (Low) of electric efficiency savings estimated for National Grid's customer base.

Table 2-3. Electric Savings by Sector for Block Island (2021-2026 Average Incremental Lifetime Savings; All Scenarios)

Sector	Max	Mid	Low
Residential	0.21	0.16	0.09
Residential Low Income	0.02	0.02	0.02
Commercial	16.05	13.95	11.62
Industrial	1.89	1.38	1.04
Total	*18.2*	*15.5*	*12.8*

Units: GWh

Table 2-4. Electric Savings by Sector for PUD (2021-2026 Average Incremental Lifetime Savings; All Scenarios)

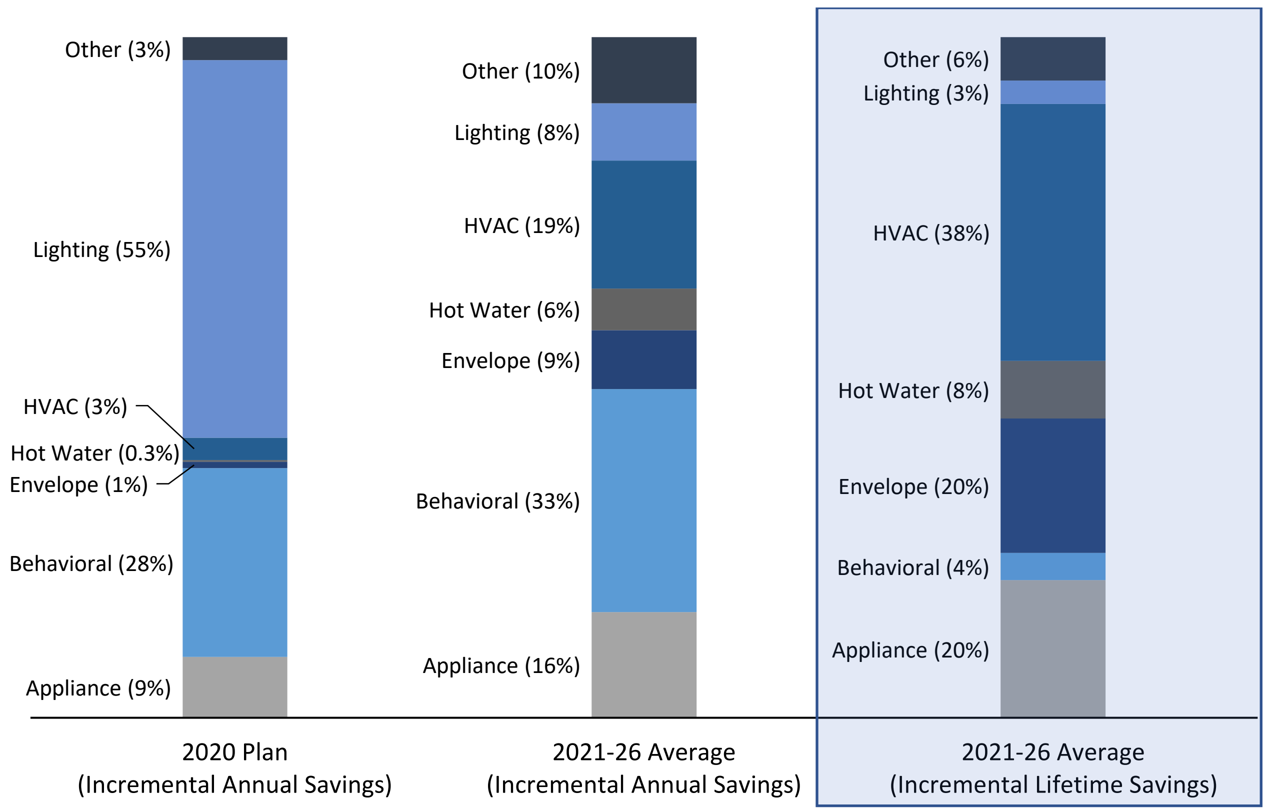
Sector	Max	Mid	Low
Residential	6.70	5.13	2.87
Residential Low Income	0.65	0.65	0.59
Commercial	16.78	14.59	12.16
Industrial	1.98	1.45	1.09
Total	*26.1*	*21.8*	*16.7*

Units: GWh

2.2.2 Residential Program Savings by End-use

For the residential and residential low-income sectors, incremental lifetime savings are distributed among multiple end-uses with the plurality (38%) coming from HVAC measures and significant amounts coming from appliance (20%) and envelope (20%) measures (see right-hand bar in Figure 2-6).

Figure 2-6. Proportion of Residential and Residential Low-Income Electric Savings by End-use (Mid Scenario)



Note: Highlighted bar displays 2021-26 average incremental lifetime savings as estimated in this study.

If measured in terms of incremental annual savings, however, the relative size of behavioral measures (i.e. home energy reports) to overall residential electric savings becomes much more pronounced – increasing from 4% of average incremental lifetime savings to 33% of average incremental annual savings. The reason behavioral measures represent a much smaller portion of incremental lifetime savings is due to an assumed savings persistence of one year for home energy reports (for further discussion on this point, see Section 2.3.2 Residential Program Savings by End-use under

Natural Gas).

Home Energy Reports

For both residential electric and natural gas efficiency savings, behavioral measures (i.e. home energy reports) provide an outsized proportion of residential incremental annual savings relative to their portion of residential incremental lifetime savings. The reason for this difference is that savings from home energy reports only persist for a single year under the assumption that savings would dissipate in the event the program is discontinued. For other technologies, such as efficient furnaces or air conditioners, savings incentivized through a program will continue to exist even if the program is discontinued later.

It is also important to note that while home energy reports generate direct savings through behavioral changes, they are also an effective enabling strategy to drive uptake of other efficiency measures, which is not explicitly captured in this study.

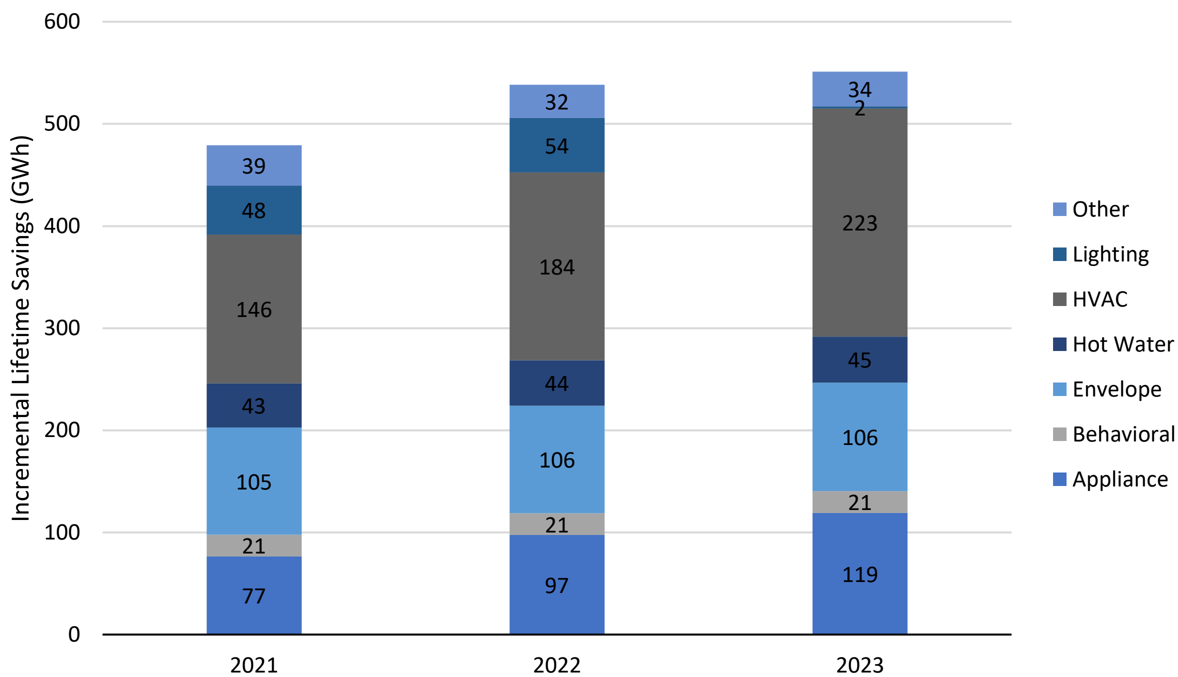
When compared to incremental annual savings targets in National Grid's 2020 Energy Efficiency Plan, the relative reduction in importance of lighting measures is evident. During the study period, lighting savings only contribute 8% of residential incremental annual savings, while the 2020 EE Plan assumes 55% of incremental annual savings will come from these measures. The discrepancy remains in absolute terms as well. Under the Low scenario, the study finds similar amounts of residential non-lighting electric annual incremental savings as assumed in the 2020 EE Plan (40 GWh vs 37 GWh, respectively). However, the 2020 EE Plan assumes approximately 47 GWh of incremental annual savings from lighting measures while the study finds approximately 14 GWh of incremental annual savings from lighting under the Low scenario.

This difference is due to the following two reasons:

- **The study does not include savings from standard bulbs (A-Lamps)**. These bulbs are ubiquitous in RI households, and while the 2020 EE Plan includes savings from these measures, the study has not included them as LEDs are expected to become the new baseline technology. Traditionally, savings from standard bulb measures have provided the bulk of efficiency program savings as program administrators provided incentives to nudge customers to purchase more efficient bulbs. The study, however, assumes that savings from standard bulb measures will no longer be claimable by 2021 due to market transformation, thus significantly reducing the amount of lighting savings opportunities.
- **The study does not include savings from specialty bulbs after 2022**. Residential homes also contain many specialty bulbs – providing opportunities to incentivize the use of more efficient bulbs. However, similar to standard bulbs, the market for specialty bulbs is quickly transforming. By the beginning of 2023, the study assumes the market for these bulbs is completely transformed, with LEDs becoming the new baseline technology. Most residential lighting savings in the study occur during the first two years of the study (2021-22) when savings from specialty bulbs are still available. In these two years, lighting measures still contribute 25% of incremental annual savings in the residential sector under the Low scenario, which is still far below the 55% of savings assumed in the 2020 EE Plan. However, the study finds that even with the loss of many residential lighting energy savings opportunities, there are other opportunities to maintain electric savings in Rhode Island. As seen in Figure 2-7, residential

incremental lifetime savings grow over the first three years of the study as savings from non-lighting measures ramp up.

Figure 2-7. Residential and Residential Low-Income Electric EE Savings by End-use (2021-23; Incremental Lifetime Savings; Mid Scenario)



The top ten residential electric efficiency measures in terms of incremental lifetime savings are listed in Table 2-5 below. The top two measures suggest there is a significant opportunity to drive savings by incentivizing the use of high-efficiency ductless mini-split heat pumps (DMSHP). Heating systems such as DMSHP have long useful lives, therefore incentivizing the purchase of more efficient systems results in significant incremental lifetime savings.

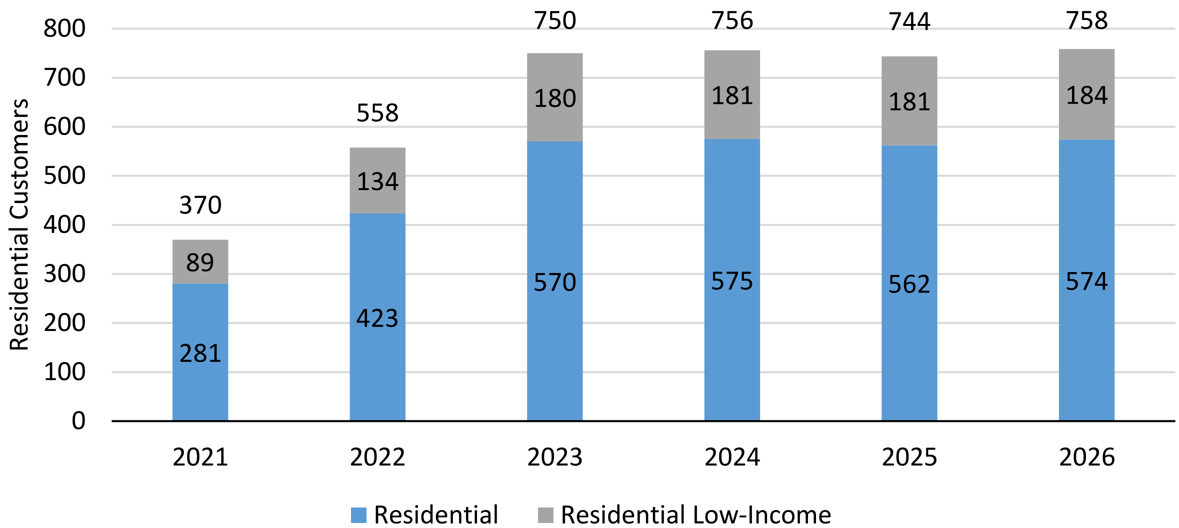
Table 2-5. Top 10 Residential and Residential Low-Income Electric EE Measures by 2021-26 Average Incremental Lifetime Savings (Mid Scenario)

Measure	Description	GWh
Electric Resistance to DMSHP	The installation of a DMSHP to displace heating from an electric resistance heating system	77
Ductless Mini-split Heat Pump (DMSHP)	The installation of a higher efficiency DMSHP instead of a standard DMSHP in homes with existing DMSHP (i.e. does not result in heating electrification)	52
Air Sealing	Thermal shell air leaks are sealed through strategic use and location of air-tight materials	42
Thermostat Wi-Fi	The installation of a new thermostat for reduced heating and cooling consumption through configurable and automatic settings	36
Refrigerator	The installation of a high-efficiency refrigerator	31
Attic Insulation	The installation of insulation to the attic/ceiling	29
Advanced Smart Strips	The use of power strips with controls to manage both active and standby power consumption of connected appliances	29
Heat Pump Water Heater (HPWH)	The installation of a heat pump water heater in place of an electric resistance water heater	28
Refrigerator Recycle	The retirement of old, inefficient refrigerators	25
Home Energy Report	A report sent to customers that displays home energy consumption in comparison with peers and prompts energy conserving behavior	22

Roughly 7% of residential customers primarily heat their homes with electric resistance systems.[34] Figure 2-8 illustrates the number of customers that would be anticipated to adopt DMSHP to displace electric resistance heating under the Mid scenario to achieve 77 GWh of incremental lifetime savings each year, on average. The study assumes measure participation ramps up over the first three years of the study to reach the full achievable potential of 750 customers per year by 2023 under the Mid scenario. Replacing electric resistance heating with a DMSHP can significantly reduce a customer's heating energy consumption as DMSHP typically have efficiencies two to three times greater than electric resistance systems. The study estimates a typical residential customer adopting this measure will save between 2,700 to 7,600 kWh per year depending on their annual heating load. Since DMSHP have a typical useful life of 18 years, this measure translates into 36 to 103 GWh of lifetime electric savings per customer – a considerable amount of savings.

[34] Electric resistance heating is more prevalent in multi-family and low-income households, with 10% and 9% of these households primarily heating with electric resistance systems, respectively.

Figure 2-8. Number of Residential Customers Adopting DMSHP to Displace Electric Resistance Heating (2021-26; Mid Scenario)

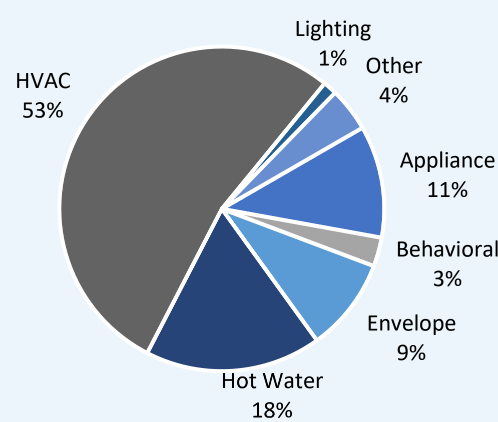


Low-Income Savings

For residential low-income customers specifically, the study finds a greater proportion of electric incremental lifetime savings come from HVAC and water heating measures relative to residential customers as a whole.

Under the Mid scenario, over half of residential low-income savings come from HVAC measures, while only 38% come from these measures in the residential sector. For water heating measures, 18% of residential low-income savings come from these measures compared to 8% for all residential customers.

Figure 2-9. Proportion of Residential Low-Income Electric Savings by End-use (Mid Scenario)



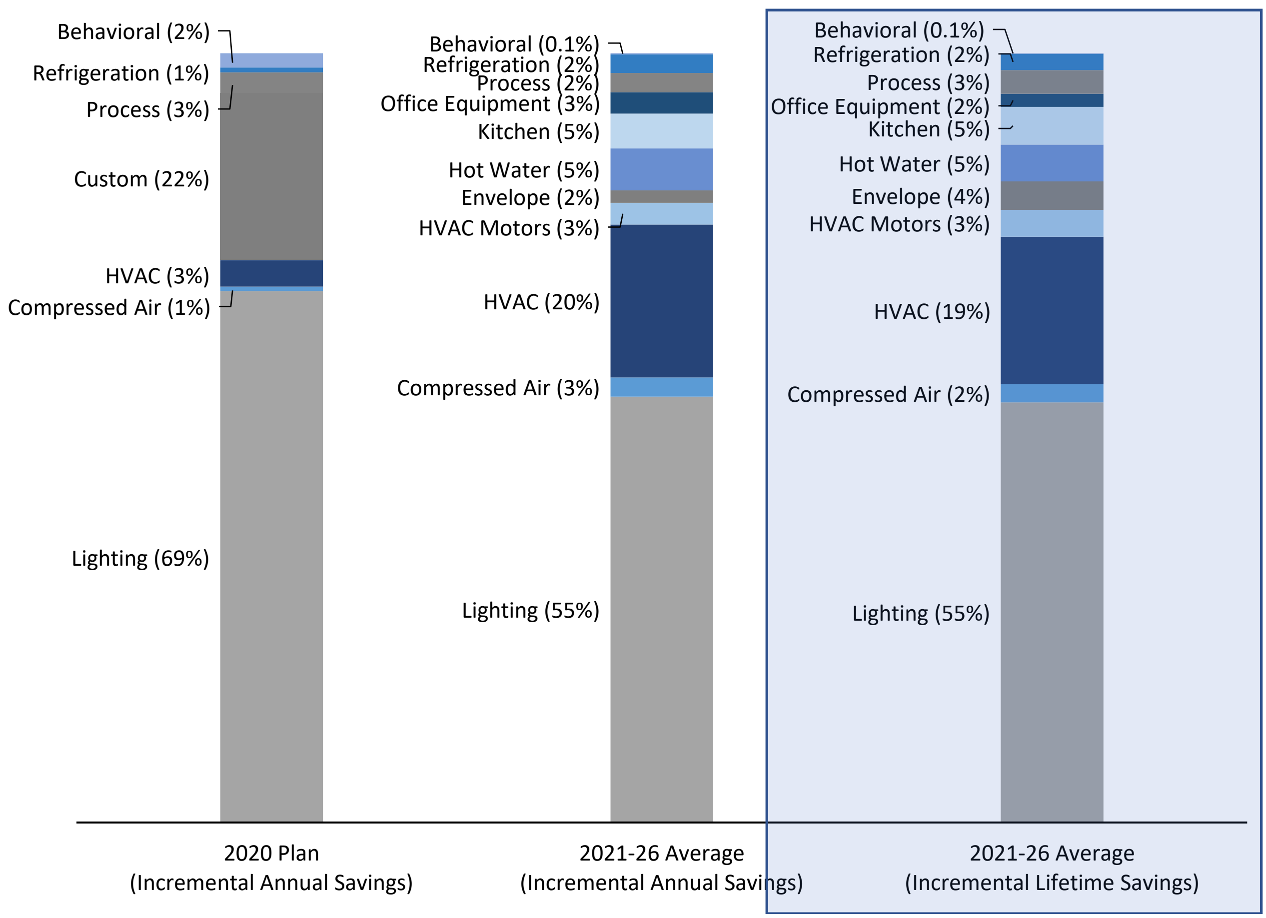
2.2.3 C&I Program Savings by End-use

On the commercial and industrial (C&I) side , more than half of incremental lifetime electric efficiency savings come from lighting measures (see right-hand bar of Figure 2-10). The relative proportion of savings by end-use does not vary significantly when measured by incremental lifetime and annual savings. Figure 2-10 below provides a breakdown of C&I savings by measure class. It shows that:

- **C&I lighting remains by far the largest opportunity, both in terms of annual and lifetime savings.** While Tubular LEDs (TLEDs) are becoming a more and more important commercial lighting technology, there has not yet been the same level of market transformation as has been seen with A-Lamps and specialty bulbs. As a result, programs that incentivise efficient commercial lighting technologies are expected to continue to offer significant potential over the study period.

- **Overall, the annual and lifetime savings breakdowns are very similar, suggesting that the measures have similar effective useful lives (EUL).** Unlike in the residential sector, there are few very short EUL measures (such as HERs) and most savings come from measures with 10 year + EULs.

Figure 2-10. Proportion of C&I Electric Savings by End-use (Mid Scenario)



Note: Highlighted bar displays 2021-26 average incremental lifetime savings as estimated in this study. Custom savings for the 2020 Plan include savings from multiple end-uses that are disaggregated as part of the study.

Lighting measures also compose six of the top ten C&I electric efficiency measures as shown in Table 2-6. Three of the four remaining measures relate to the use of heat pumps to provide more efficient space heating and cooling and domestic hot water.

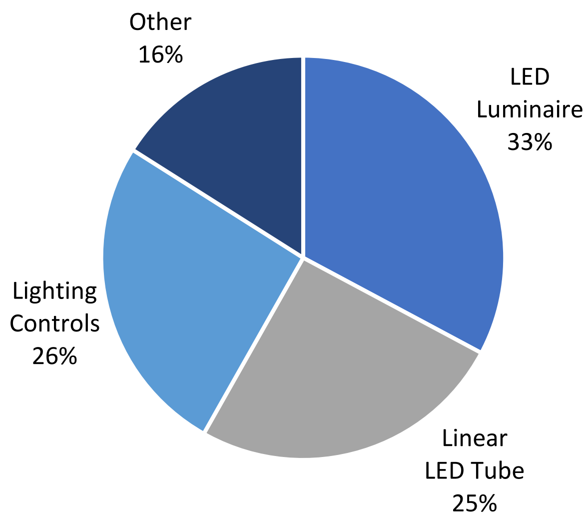
Table 2-6. Top 10 C&I Electric EE Measures (Average Incremental Lifetime Savings; Mid Scenario)

Measure	Description	GWh
LED Luminaire	The installation of an LED in a luminaire lighting fixture	203
Linear LED Tube	The installation of an LED in a linear tube lighting fixture	157
Lighting Controls (Interior), Occupancy	The installation of a device to turn lights on/off in the presence/absence of room occupants	74
Advanced Network Lighting Controls	The installation of a control system that enables energy savings through a variety of methods	64
LED Pole Mounted (Exterior)	The installation of an LED for an exterior pole mounted fixture	53
Air Source Heat Pumps (ASHP)	The installation of a higher efficiency ASHP instead of a standard ASHP in businesses with existing ASHP (i.e. does not result in heating electrification)	39
Energy Management System (EMS)	The installation of system to more efficiently manage energy consuming equipment and activities within a building	25
Heat Pump Water Heater (HPWH)	The installation of a heat pump water heater in place of an electric resistance water heater	24
Electric Resistance to DMSHP	The installation of a DMSHP to displace heating from an electric resistance heating system	24
LED High Bay	The installation of an LED in a high bay lighting fixture	21

Lighting will continue to play an important role in C&I programs over the study period. These savings are concentrated among three measure groups – LED Luminaires, Linear LED Tubes, and Lighting Controls – as shown in Figure 2-11.

While markets are shifting for luminaires and tubes toward more common adoption of TLEDs, advanced lighting controls, including networked lighting, is a growing opportunity as new technologies and products integrate efficiency savings with increased functionality and non-energy benefits. These offer an emerging opportunity that also faces notable challenges including limited cross-compatibility among products from different manufacturers, limited customer awareness of the options and benefits, and timing re-lamping efforts with controls change-outs. Achieving the potential savings from advanced lighting controls will likely require investment to identify the most effective delivery strategies and tracking product development and roll out.

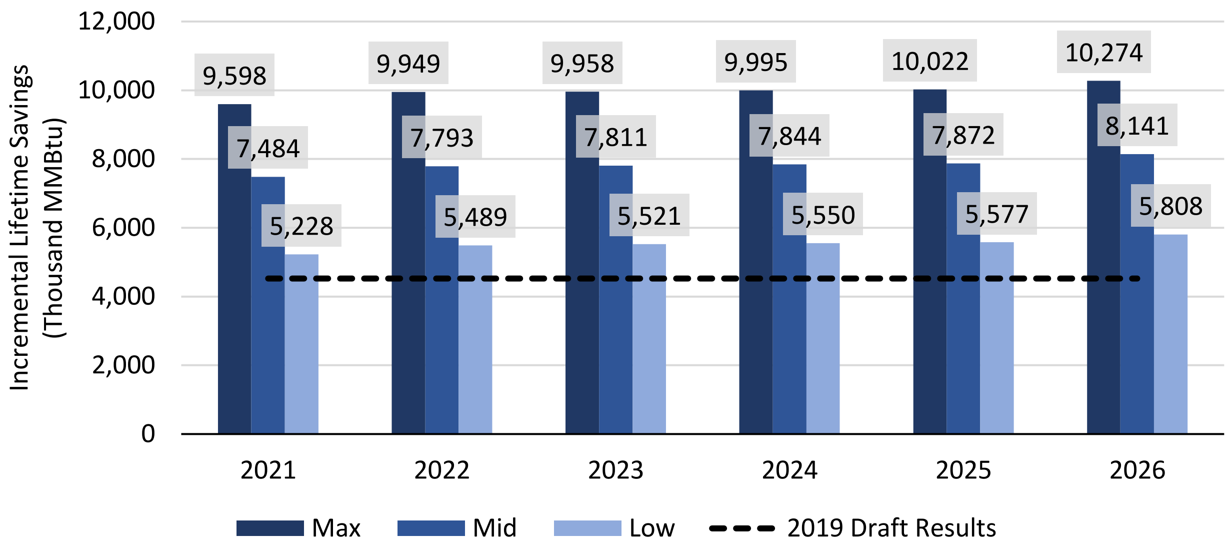
Figure 2-11. Proportion of C&I Lighting Savings by Measure Type (2021-26 Average Incremental Lifetime Savings; Mid Scenario)



2.3 Natural Gas Program Savings

The study estimates that efficiency programs can procure an average of 5,529 thousand MMBtu (Low) to 9,966 thousand MMBtu (Max) of incremental lifetime savings each year during the study period. As shown in Figure 2-12, incremental lifetime savings grow year-over-year – particularly between 2021 and 2022 as measures ramp up – which coincides with increasing overall natural gas usage in Rhode Island.

Figure 2-12. Natural Gas Incremental Lifetime Savings by Year (2021-26; All Scenarios)



Compared to Draft 2019 Results and the 2020 EEPP, the study estimates that natural gas efficiency savings under business-as-usual (i.e. Low scenario) are higher than achieved in 2019 or planned for 2020. Under the Low scenario, incremental lifetime savings in 2021 are approximately 8.5% higher than the 2020 EEPP. This is a similar increase in incremental lifetime savings indicated between Draft 2019 Results and the 2020 EEPP, where a 6.5% increase is predicted.

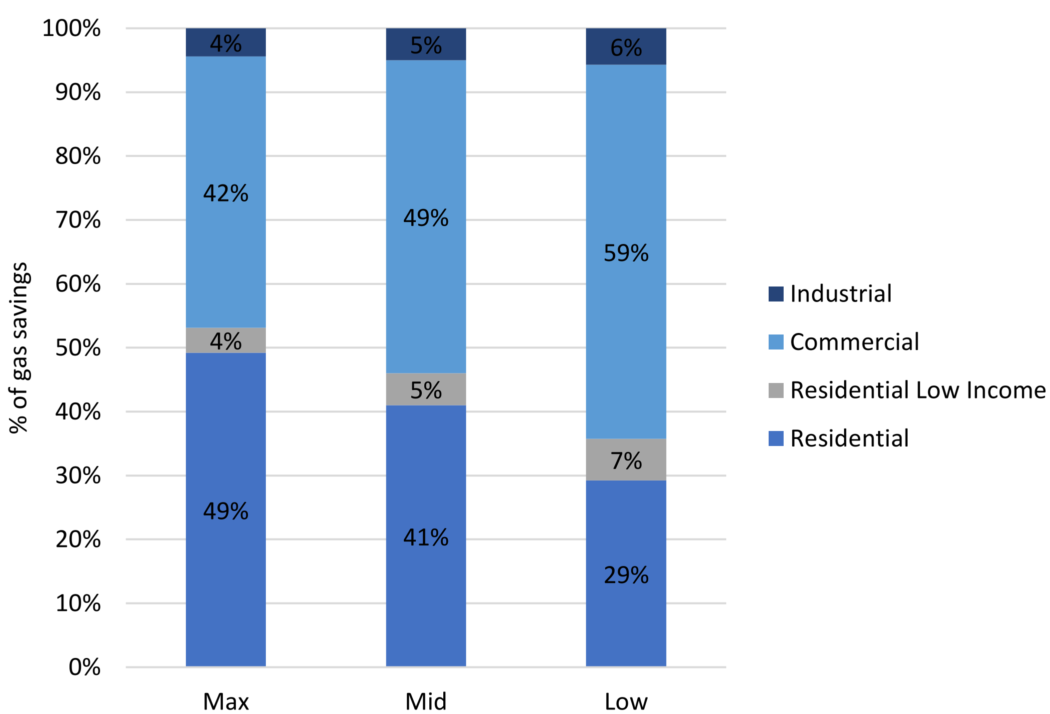
Table 2-7. Natural Gas EE Incremental Lifetime Savings, Incremental Annual Savings, and Incremental Annual Savings as Percentage of Overall Sales by Year (All Scenarios)

Program Savings	Scenario	2021	2022	2023	2024	2025	2026	Average	Draft 2019 Results	2020 EEPP
Incremental Lifetime Savings (Thousand MMBtu)	Max	9,598	9,949	9,958	9,995	10,022	10,274	**9,966**	4,524	4,816
	Mid	7,484	7,793	7,811	7,844	7,872	8,141	**7,824**		
	Low	5,228	5,489	5,521	5,550	5,577	5,808	**5,529**		
Incremental Annual Savings (Thousand MMBtu)	Max	749	771	788	791	794	818	**785**	451	447
	Mid	623	641	659	662	664	688	**656**		
	Low	480	496	512	514	517	537	**509**		
% of Annual Sales	Max	1.8%	1.8%	1.8%	1.8%	1.8%	1.9%	**1.8%**	1.1%	1.1%
	Mid	1.5%	1.5%	1.5%	1.5%	1.5%	1.6%	**1.5%**		
	Low	1.1%	1.2%	1.2%	1.2%	1.2%	1.2%	**1.2%**		

2.3.1 Program Savings by Market Sector

Under the Low scenario, the bulk of natural gas savings come from the commercial sector as shown in Figure 2-13. However, as incentives and enabling activities increase under the Mid and Max scenarios, savings from the residential sector grow at a much faster rate than other sectors – becoming nearly 50% of overall natural gas savings under the Max scenario.

Figure 2-13. Proportion of Gas Savings by Sector (2021-26 Average Incremental Lifetime Savings; All Scenarios)



Similar to electric efficiency savings, savings from the residential sector increase at a faster rate between the Low and Max scenarios relative to other sectors. Savings from the residential sector increase by over 200% between the Low and Max scenarios, while savings from the remaining sectors increase by less than 40%. Compared to Draft 2019 Results and the 2020 EEPP, residential savings under the Low scenario are similar, while commercial savings are significantly higher suggesting there is continued room to grow commercial savings under business-as-usual conditions. The study estimates slightly lower potential savings for the residential low-income sector, which is likely due to discrepancies between customer segmentation used in the study and customers that are eligible for and participate in the low-income programs in Rhode Island as previously described in Section 2.2.1 Program Savings by Market Sector for electric potential.

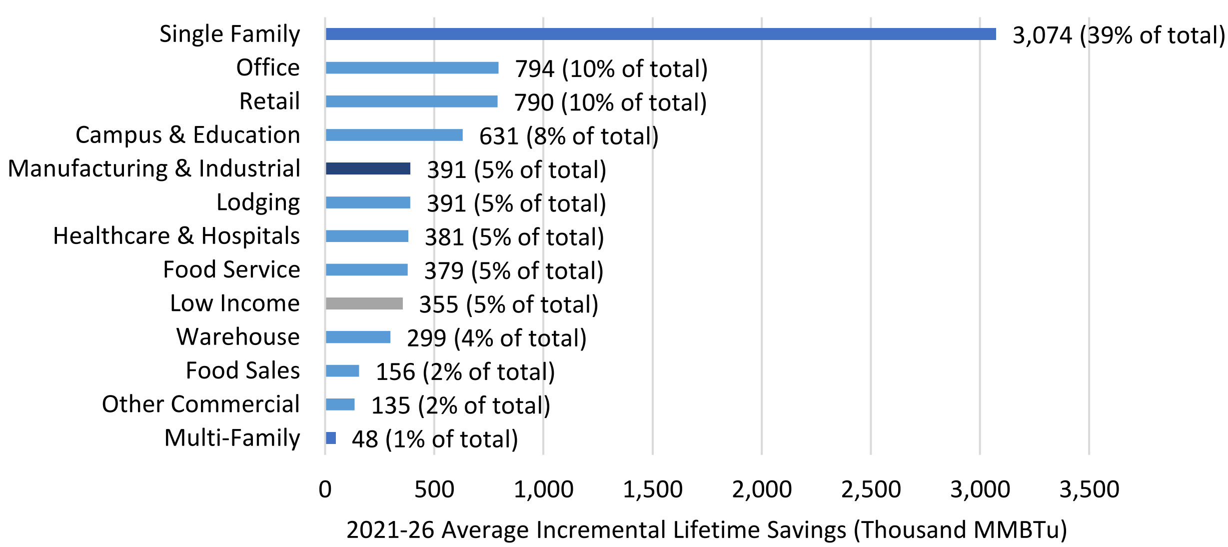
Table 2-8. Natural Gas EE Savings by Sector (2021-2026 Average Incremental Lifetime Savings; All Scenarios)

Sector	Max	Mid	Low	Draft 2019 Results	2020 EEPP
Residential	4,905	3,209	1,616	1,740	1,527
Residential Low-Income	391	391	360	505	650
Commercial	4,230	3,833	3,237	2,279	2,639
Industrial	439	391	316		
Total	*9,966*	*7,824*	*5,529*	*4,524*	*4,816*

Units: Thousand MMBtu

The single-family segment accounts for the plurality of natural gas savings under all scenarios. Under the Mid scenario, single family represented 39% of natural gas efficiency savings (see Figure 2-14).

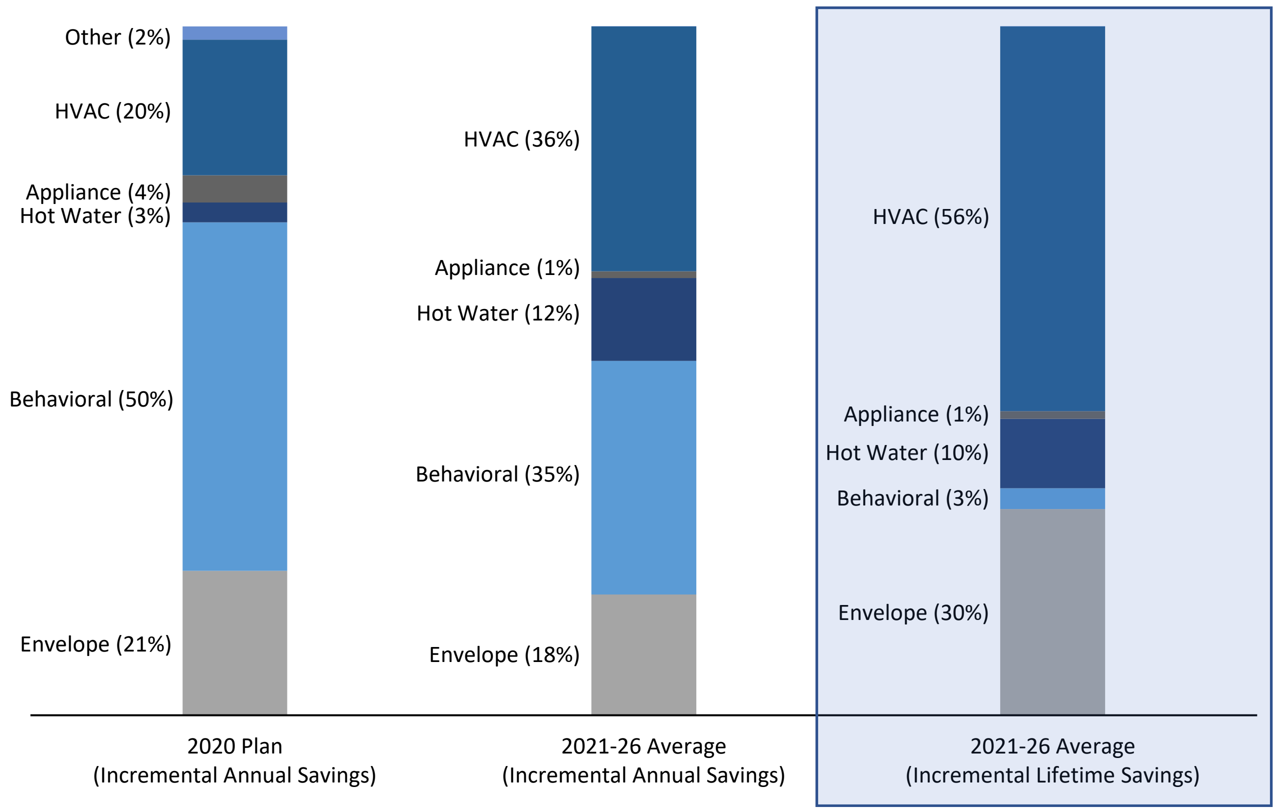
Figure 2-14. Natural Gas EE Savings by Segment (Average Incremental Lifetime Savings; Mid Scenario)



2.3.2 Residential Program Savings by End-use

Within the residential sector, gas efficiency savings primarily come from measures that reduce natural gas consumption for heating – whether through more efficient heating systems (i.e. HVAC measures) or better weatherized homes (e.g. envelope measures). Under the Mid scenario, approximately 56% of savings come from HVAC measures and 30% come from envelope measures (see right hand bar of Figure 2-15 below).

Figure 2-15. Proportion of Residential Natural Gas EE Savings by End-use (Mid Scenario)



Note: Highlighted bar represents 2021-26 average incremental lifetime savings as estimated in this study.

Similar to electric efficiency savings, the relative size of home energy reports (i.e. behavioral measures) becomes much less pronounced when viewed in terms of incremental lifetime savings – decrease from 35% of incremental annual savings to 3% of incremental lifetime savings.

When compared to the 2020 EEPP Plan, the study finds a greater proportion of incremental annual savings coming from HVAC and water heating measures under the Mid scenario, while the 2020 plan achieves a greater proportion of its savings from home energy reports. This is attributable to the following:

- **The Mid scenario delivers significantly higher HVAC savings than the Low scenario, which more closely matches the current programs.** For HVAC measures, the Mid scenario includes almost twice the level of HVAC savings as compared to the Low scenario. While the study finds similar absolute amounts of savings between the Low scenario (50 thousand MMBtu in incremental annual savings) and 2020 Plan (45 thousand MMBtu in incremental annual savings), the growth in HVAC measures under the Mid scenario increases its relative importance to the rest of the residential gas portfolio.

This is driven by an assumed significant increase in incentive levels for HVAC measures between the Low and Mid scenarios – increasing from an average incentive of 36% (Low) to 75% (Mid).

- **Similarly for water heating measures, the Mid scenario offers significant growth over the Low scenario:** While water heating savings experience modest growth under the Mid scenario, the study also finds significantly more savings from these measures under the Low scenario (28 thousand MMBtu in incremental annual savings) compared to the 2020 Plan (7 thousand MMBtu in incremental annual savings). This suggests there are significantly more savings from water heating measures than currently being achieved.

- **The relative importance of Home Energy Reports drops as achievable savings increase among scenarios, because Home Energy Reports participation is already at its maximum under current programs.** As other measures grow in the Mid and Max scenarios, the relative proportion of home energy reports declines while overall savings from the measure remain the same.

Table 2-9. Residential Natural Gas EE Savings by End Use (2021-26 Average Incremental Lifetime Savings; All Scenarios)

End use	Max	Mid	Low
Appliance	83	41	12
Behavioral	110	110	109
Envelope	1,785	1,083	764
Water Heating	475	365	232
HVAC	2,866	2,021	874

Units: GWh

As shown in Figure 2-16, the vast majority of savings within the HVAC class come from boiler, furnace, and smart thermostat measures, which are also the top three residential natural gas efficiency measures (see Table 2-10).

Figure 2-16. Proportion of Residential HVAC Natural Gas EE Savings by Measure Type 2021-26 Average Incremental Lifetime Savings; Mid Scenario)

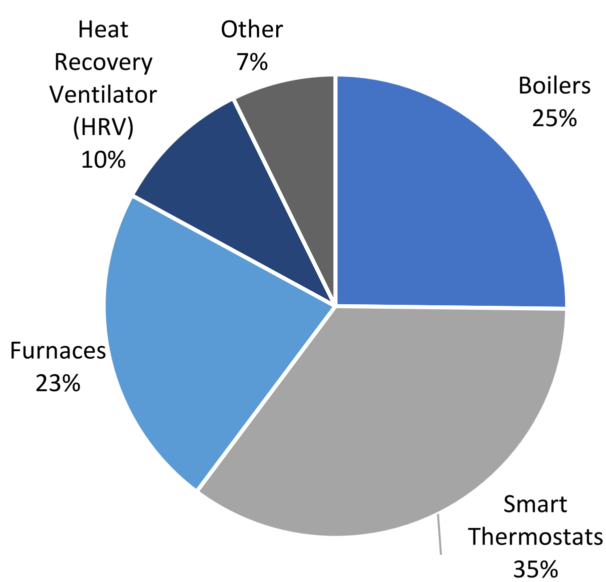


Table 2-10. Top 10 Residential Natural Gas EE Measures (Average Incremental Lifetime Savings; Mid Scenario)

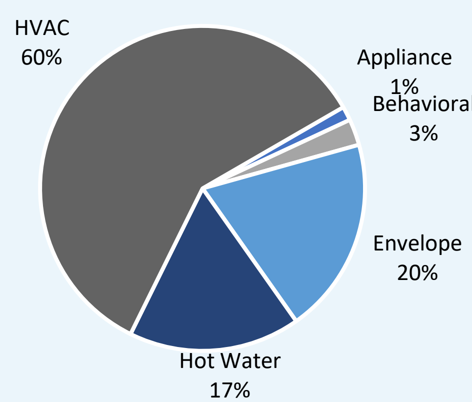
Measure	Description	Thousand MMBtu
Thermostat Wi-Fi	The installation of a new thermostat for reduced heating and cooling consumption through configurable and automatic settings	708
Furnace	The installation of a high-efficiency furnace	459
Boiler	The installation of a high-efficiency boiler	410
Attic Insulation	The installation of insulation to the attic/ceiling	372
Air Sealing	Thermal shell air leaks are sealed through strategic use and location of air-tight materials	302
New Home Construction	The construction of an EnergyStar certified home	226
Heat Recovery Ventilator (HRV)	The installation of an HRV that reclaims energy from exhaust airflows	198
Basement Insulation	The installation of insulation to the basement	150
Low Flow Shower Head	The installation of a low flow shower head	125
Duct Insulation	The installation of insulation to the ducting system	123

Low-Income Savings

Relative to the residential sector as a whole, the low-income programs have a higher proportion of savings coming from HVAC and water heating measures, while a smaller proportion coming from envelope measures.

The top measures for the low-income sector closely mirror the residential sector as with whole with smart thermostats, boilers, and furnaces among the top four measures. However, the third highest savings measure for low-income customers is the installation of more efficient gas storage water heaters, which does not make the top ten list for the residential sector.

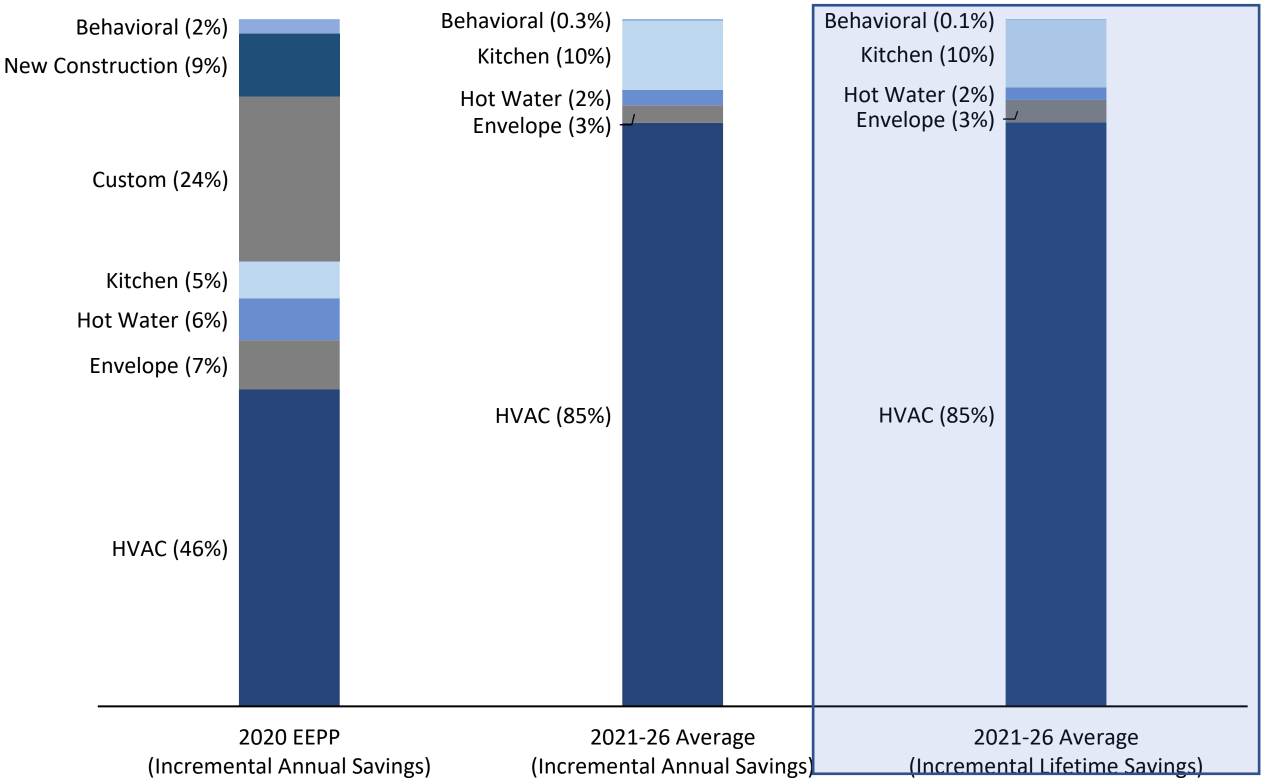
Figure 2-17. Proportion of Residential Low-Income Natural Gas Savings by End-use (Mid Scenario)



2.3.3 C&I Program Savings by End-use

HVAC measures compose the vast majority of C&I natural gas efficiency incremental lifetime and annual savings (see middle and right-hand bars in Figure 2-18.

Figure 2-18. Proportion of C&I Natural Gas EE Savings by End-use (2021-26 Average Incremental Lifetime Savings; Mid Scenario)



Note: Highlighted bar represents 2021-26 average incremental lifetime savings as estimated in this study. Custom savings for the 2020 EEPP include savings from multiple end-uses that are disaggregated as part of the study.

Compared to the 2020 EEPP, the study estimates a greater proportion of savings from HVAC and kitchen related measures. This is partially attributable to savings that may result from HVAC or kitchen measures in the study being classified as "custom" in the 2020 EEPP.

Figure 2-19. Proportion of C&I HVAC Natural Gas EE Savings by Measure Type (2021-26 Average Incremental Lifetime Savings; Mid Scenario)

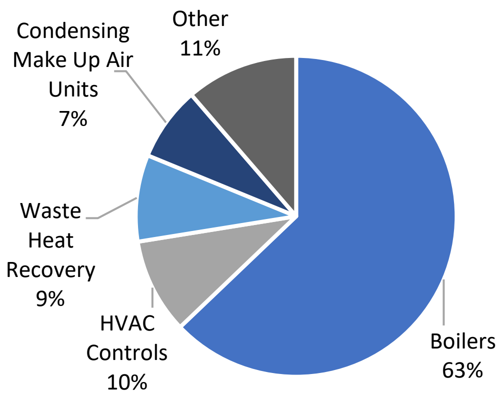


Table 2-11. C&I Natural Gas EE Savings by End Use (2021-26 Average Incremental Lifetime Savings; All Scenarios)

End use	Max	Mid	Low
Behavioral	6	5	3
Envelope	207	142	93
Water Heating	90	80	69
HVAC	4,118	3,746	3,161
Kitchen	477	433	376

Units: Thousand MMBtu

As shown in Figure 2-19, the majority of savings within the HVAC class come from boiler-related measures, which include more efficient boilers, steam traps, and boiler reset controls – the top three C&I natural gas EE measures (see Table 2-12).

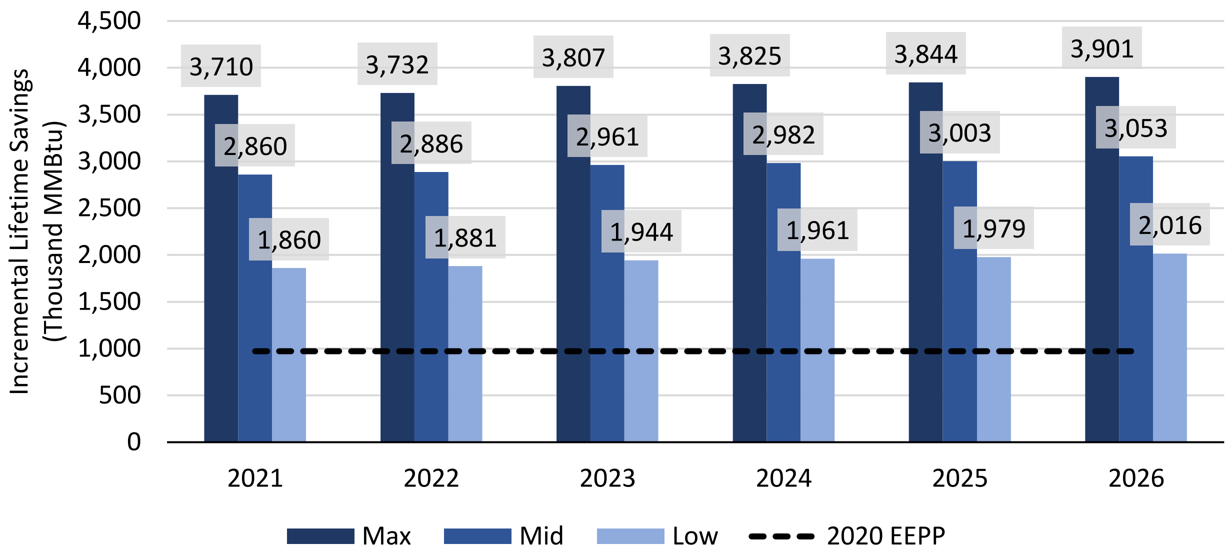
Table 2-12. Top 10 C&I Natural Gas EE Measures (Average Incremental Lifetime Savings; Mid Scenario)

Measure	Description	Thousand MMBtu
Boiler	The installation of a high-efficiency boiler	1,204
Steam Trap	The repair of a failed open and leaking steam trap	664
Boiler Reset Control	The installation of a boiler reset control to automatically control the boiler water temperature based on outdoor air temperature	342
Waste Heat Recovery	The installation of devices to improve waste heat recovery	327
Condensing Make Up Air Unit	The installation of a high-efficiency condensing make up air unit	280
Fryer	The installation of a more efficient gas fryer	218
Demand Control Ventilation (DCV)	The installation of devices to control outside ventilation based on the ventilation demands created by indoor occupants	154
Building Shell Air Sealing	Thermal shell air leaks are sealed through strategic use and location of air-tight materials	136
Kitchen Demand Control Ventilation	The installation of devices to control outside ventilation based on the ventilation demands created by indoor occupants	118
Steam Boiler	The installation of a high-efficiency steam boiler	108

2.4 Delivered Fuel Program Savings

The study estimates that delivered fuel efficiency programs can procure an average of 1,940 thousand MMBtu (Low) to 3,803 thousand MMBtu (Max) of incremental lifetime savings in delivered fuels each year during the study period. As shown in Figure 2-20, incremental lifetime savings grow slightly year-over-year.

Figure 2-20. Delivered Fuel Incremental Lifetime Savings by Year (2021-26; All Achievable Scenarios)



Note: National Grid's Draft 2019 Fourth Quarter Report did not include oil and propane savings, therefore the 2020 EEPP benchmark is included in the above figure.

As shown in Table 2-13, the study finds significantly more delivered fuel savings than are currently planned through existing programs as National Grid offers a limited set of measures for residential customers and no measures for commercial and industrial customers that claim delivered fuel savings due to historically limited approved funding for these measures. The study estimates the potential for delivered fuel efficiency savings under the Low scenario is more than double the savings assumed in the 2020 EEPP Plan.

Table 2-13. Delivered Fuel EE Incremental Lifetime Savings, Incremental Annual Savings, and Incremental Annual Savings as Percentage of Overall Sales by Year (All Scenarios)

Program Savings	Scenario	2021	2022	2023	2024	2025	2026	Average	Draft 2019 Results	2020 EEPP
Incremental Lifetime Savings (Thousand MMBtu)	Max	3,710	3,732	3,807	3,825	3,844	3,901	*3,803*	*N/A*	*972*
	Mid	2,860	2,886	2,961	2,982	3,003	3,053	*2,958*		
	Low	1,860	1,881	1,944	1,961	1,979	2,016	*1,940*		
Incremental Annual Savings (Thousand MMBtu)	Max	202	202	220	221	222	225	*215*	*N/A*	*52*
	Mid	155	156	173	174	176	179	*169*		
	Low	98	98	113	114	115	117	*109*		
% of Annual Sales	Max	0.9%	0.9%	1.1%	1.1%	1.1%	1.2%	*1.0%*	*N/A*	*0.2%*
	Mid	0.7%	0.7%	0.8%	0.9%	0.9%	0.9%	*0.8%*		
	Low	0.4%	0.5%	0.5%	0.6%	0.6%	0.6%	*0.5%*		

Note: National Grid's Draft 2019 Fourth Quarter Report did not include oil and propane savings, therefore benchmarks are not included in the above table.

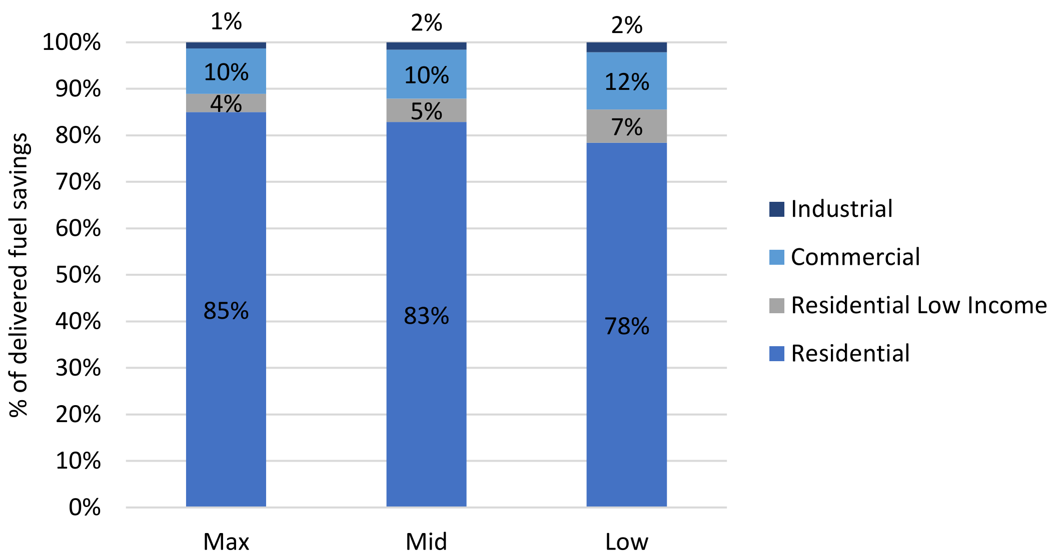
Electric and Gas Savings Attributable to Delivered Fuel Measures

The vast majority of delivered fuel measures applied in this study would be anticipated to provide at least some electric or gas savings. For example, the top three residential measures (air sealing, smart thermostats, and attic insulation) would all be expected to marginally reduce electricity consumption through reducing the run time of electric HVAC fans or pumps.

2.4.1 Program Savings by Market Sector

As shown in Figure 2-21, the vast majority of delivered fuel savings under each scenario come from the residential sector with 78% (Low) to 85% (Max) of average incremental lifetime savings, which is greater than the residential sector's share of overall delivered fuel consumption in Rhode Island (approximately 70%). This greater opportunity for efficiency in the residential sector relative to overall consumption reflects the greater portion of residential delivered fuel use that is amenable to efficiency measures. Most residential delivered fuel use is for space and water heating, while C&I use has a greater portion used for processes that may not be easily modified for greater efficiency.

Figure 2-21. Proportion of Delivered Fuel Savings by Sector (2021-26 Average Incremental Lifetime Savings; All Scenarios)



As can be seen in Table 2-14, the study estimates significantly more delivered fuel efficiency potential for all sectors compared to the 2020 EEPP except for the residential low-income sector, which is likely due to discrepancies between customer segmentation used in the study and customers that are eligible for and participate in the low-income programs in Rhode Island as previously described in Section 2.2.1 Program Savings by Market Sector for electric potential.

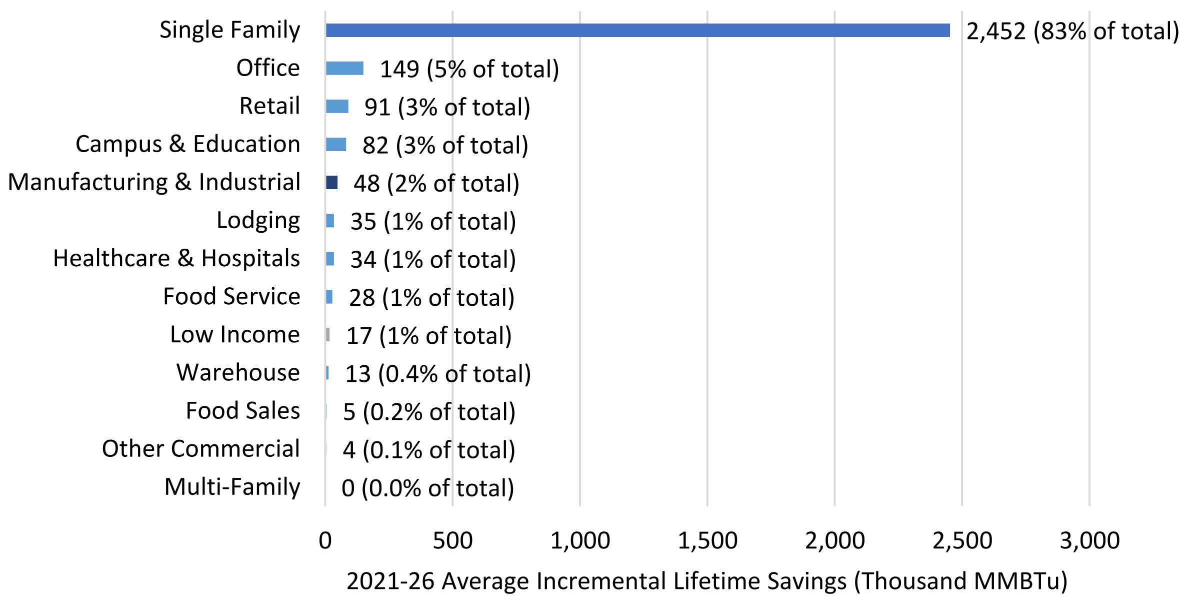
Table 2-14. Delivered Fuel EE Savings by Sector (2021-2026 Average Incremental Lifetime Savings; All Scenarios)

Sector	Max	Mid	Low	2020 EEPP
Residential	3,234	2,451	1,521	712
Residential Low Income	149	149	139	260
Commercial	370	310	238	0
Industrial	50	48	41	
Total	*3,803*	*2,958*	*1,940*	*972*

Units: Thousand MMBtu

As shown in Figure 2-22, the single-family segment represents the vast majority of delivered fuel efficiency savings. Multi-family has an insignificant amount of delivered fuel savings due to low numbers of multi-family customers using delivered fuels.

Figure 2-22. Delivered Fuel EE Savings by Segment (Average Incremental Lifetime Savings; Mid Scenario)



Block Island and Pascoag Utility District

Delivered fuel efficiency savings for the Block Island and PUD are estimated by scaling estimated savings for National Grid based on each utility's relative residential and C&I customer count. A full description of this scaling process is provided in Appendix F.

As shown in Table 2-15 and Table 2-16, the study estimates there is an additional 26.1 (Low) to 48.9 (Max) thousand MMBtu of incremental lifetime savings per year in the Block Island and PUD jurisdictions. PUD has greater potential due to a greater number of residential customers relative to Block Island. Both utilities have similar amounts of commercial and industrial potential due to similar numbers of these customers in their territories. Overall, the combined estimated savings potential for PUD and Block Island is approximately 1.3% of delivered fuel savings for all scenarios as estimated for National Grid's customer base.

Table 2-15. Delivered Fuel EE Savings by Sector for Block Island Utility District (2021-26 Average Incremental Lifetime Savings; All Scenarios)

Sector	Max	Mid	Low
Residential	1.08	0.82	0.51
Residential Low Income	0.05	0.05	0.05
Commercial	5.00	4.19	3.22
Industrial	0.67	0.64	0.56
Total	*6.8*	*5.7*	*4.3*

Units: Thousand MMBtu

Table 2-16. Delivered Fuel EE Savings by Sector for Pascoag Utility District (2021-26 Average Incremental Lifetime Savings; All Scenarios)

Sector	Max	Mid	Low
Residential	34.60	26.22	16.28
Residential Low Income	1.60	1.60	1.49
Commercial	5.23	4.38	3.37
Industrial	0.71	0.67	0.58
Total	*42.1*	*32.9*	*21.7*

Units: Thousand MMBtu

2.4.2 Residential Program Savings by End-use

The vast majority of residential delivered fuel savings come from measures that reduce delivered fuel consumption for heating – whether through more efficient heating systems (i.e. HVAC measures) or better weatherized homes (e.g. envelope measures) as shown in Figure 2-23.

Figure 2-23. Proportion of Residential Delivered Fuel EE Savings by End-use (Average Incremental Lifetime Savings; Mid Scenario)

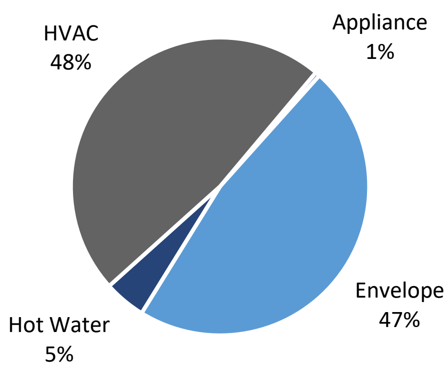


Table 2-17. Top 10 Residential Delivered Fuel Gas EE Measures (Average Incremental Lifetime Savings; Mid Scenario)

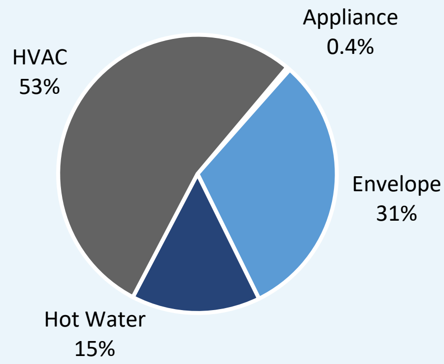
Measure	Thousand MMBtu
Air Sealing	637
Thermostat Wi-Fi	607
Attic Insulation	395
Heat Recovery Ventilator (HRV)	196
Basement Insulation	174
Boiler Reset Control	171
Boiler	132
Furnace	96
Low Flow Shower Head	68
Duct Insulation	40

Low-Income Savings

Similar to gas efficiency savings, the residential low-income sector has a higher proportion of savings coming from HVAC and water heating measures, while a smaller proportion coming from envelope measures, when compared to the residential sector as a whole.

The top delivered fuel measure for residential low-income customers is smart thermostats, which can deliver an average approximately 40 thousand MMBtu in incremental lifetime savings each year throughout the study.

Figure 2-24. Proportion of Residential Low Income Delivered Fuel Savings by End-use (Mid Scenario)



2.4.3 C&I Program Savings by End-use

The vast majority of C&I delivered fuel efficiency savings come from HVAC measures, with most of these savings coming from the top two C&I delivered fuel efficiency measures – waste heat recovery and boilers (see Table 2-18).

Figure 2-25. Proportion of C&I Delivered Fuel EE Savings by End-use (Average Incremental Lifetime Savings; Mid Scenario)

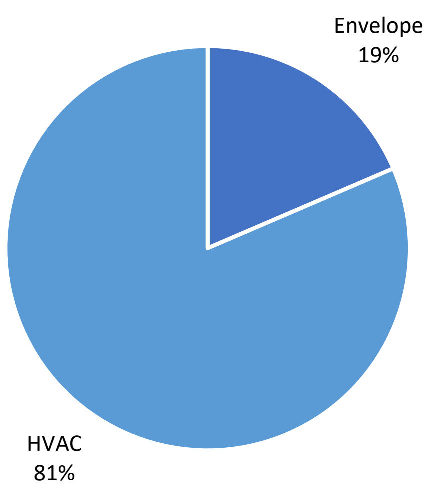


Table 2-18. Top 6 C&I Delivered Fuel Gas EE Measures (Average Incremental Lifetime Savings; Mid Scenario)

Measure	Thousand MMBtu
Waste Heat Recovery	169
Boiler	148
Building Shell Air Sealing	47
Attic/Roof Insulation	35
Energy Management System (EMS)	24
Retro-commissioning Strategic Energy Manager (RCx SEM)	14

Note: Only 6 measures are included in this table as the study has limited C&I delivered fuel measures due to limited delivered fuel consumption in the C&I sectors.

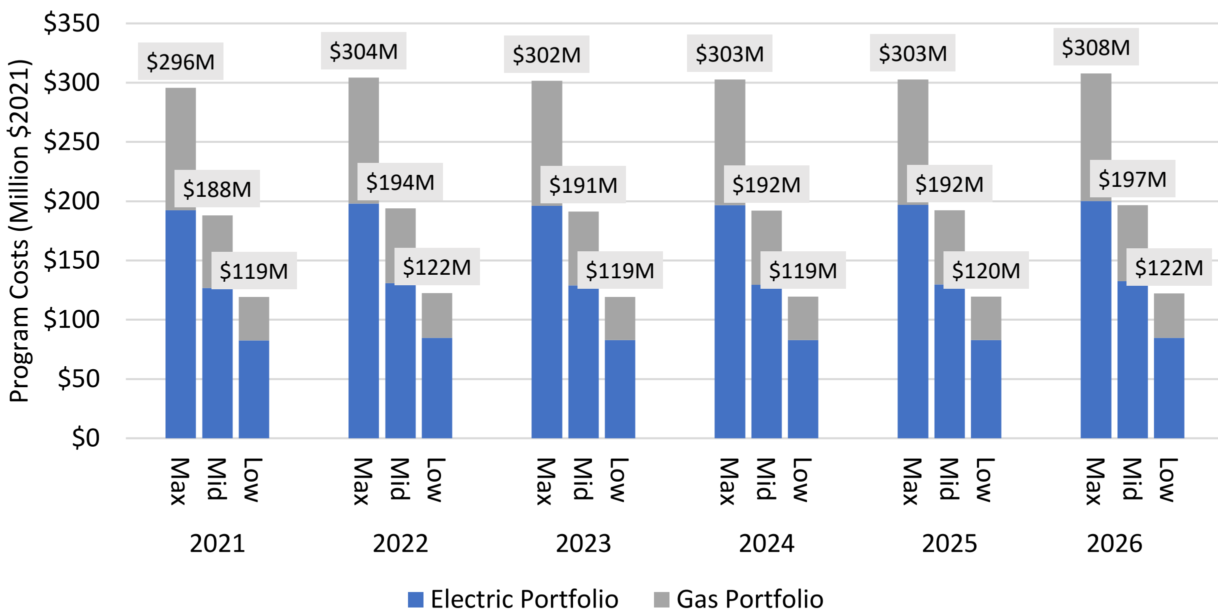
2.5 Portfolio Metrics

Overall, the study shows there is continued significant potential for energy efficiency in Rhode Island. As A-Lamps and specialty lighting markets transform (which have been foundational technologies driving historical program savings), program delivery, costs, and impacts will be affected. This section provides high-level estimated cost and benefit projections for the achievable potential scenarios. While these projections may offer a valuable directional assessment of program opportunities and the associated costs over the study period, these are largely informed by past program designs and performance in Rhode Island. However, as the efficiency technology mix evolves, and new delivery approaches are required, the actual costs and program balances could vary significantly from these projections and could be higher or lower.

2.5.1 Program Costs

The study estimates that efficiency program costs will range between an average of $120 (Low) to $302 (Max) million dollars per year. Similar to current efficiency spending, the majority of this is directed toward the electric efficiency programs as seen in Figure 2-26, which also includes spending on delivered fuel measures.

Figure 2-26. Estimated Program Costs by Year (2021-26; All Scenarios)



Note: Electric portfolio costs include incentive and implementation costs for delivered fuel measures.

Relative to Draft 2019 Results and the 2020 EEPP Plan, the study estimates a reduction in the annual program spending under a business-as-usual approach (i.e. Low scenario) as presented in Table 2-19. This is primarily driven by the elimination of program spending on A-Lamp measures, which accounts for roughly $7.9 million of 2019 spending (8% of electric portfolio spending) and $6.4 million of the 2020 EEPP (6% of electric portfolio spending).[35] The remainder of the difference may be attributable to

[35] Spending specific to A-Lamp measures was provided by National Grid.

additional costs within the reporting spending in 2019 and planned in 2020 that are not accounted for in the study (e.g. regulatory costs) as well as inherent uncertainty involved in large-scale potential studies.

Table 2-19. Estimated Program Costs by Year (All Scenarios)

Portfolio	Scenario	2021	2022	2023	2024	2025	2026	Average	2019 Results	2020 Plan
Electric	Max	$192M	$198M	$196M	$197M	$197M	$200M	**$197M**	**$99M**	**$101M**
	Mid	$127M	$131M	$129M	$129M	$130M	$132M	**$130M**		
	Low	$83M	$85M	$83M	$83M	$83M	$85M	**$83M**		
Gas	Max	$103M	$106M	$105M	$106M	$106M	$108M	**$106M**	**$30M**	**$33M**
	Mid	$61M	$63M	$62M	$63M	$63M	$64M	**$63M**		
	Low	$37M	$38M	$37M	$37M	$37M	$37M	**$37M**		
Total	*Max*	*$296M*	*$304M*	*$302M*	*$303M*	*$303M*	*$308M*	***$302M***	***$130M***	***$134M***
	Mid	*$188M*	*$194M*	*$191M*	*$192M*	*$192M*	*$197M*	***$192M***		
	Low	*$119M*	*$122M*	*$119M*	*$119M*	*$120M*	*$122M*	***$120M***		

Note: Benchmark spending metrics do not include spending on CHP, DR, or HE.

In addition to larger budgets, the average unit cost of savings increases as well under the Mid and Max scenarios as presented in Table 2-20. While the Low scenario achieves similar per unit costs for natural gas and slightly higher costs for electric (primarily due to the exclusion of A-Lamp savings, which generally have very low per unit savings costs) as the 2019 results and 2020 Plan, per unit costs under the Mid and Max scenarios increase at each step.

Table 2-20. Average Estimated Savings Unit Cost (2021-26; All Scenarios)

Metric	Max	Mid	Low	2019 Results	2020 Plan
$ per Incremental Annual kWh	$1.07	$0.82	$0.67	$0.55	$0.61
$ per Incremental Lifetime kWh	$0.098	$0.077	$0.066	$0.065	$0.069
$ per Incremental Annual MMBtu	$134.67	$95.57	$72.55	$66.79	$73.37
$ per Incremental Lifetime MMBtu	$10.61	$8.02	$6.68	$6.66	$6.80

These results are to be expected as costs will typically increase as incentives are raised and more customers participate in programs under the Mid and Max scenarios. The unit cost of savings will increase as well for two primary reasons. First, raising incentives increases the cost not just for newly acquired savings, but also for savings that would have been obtained under lower incentive levels and thus at a lower per unit cost. Second, the higher incentives and investments in enabling strategies may drive more uptake of measures with higher unit savings costs associated with their lower savings to incremental cost ratios. However, the precise magnitude of cost increases under these scenarios should be interpreted with the following caveats:

- **Cost estimates are based on historical cost data.** Fixed and variable program cost inputs were developed based on historical spending data for National Grid's efficiency programs in 2019. These inputs do not vary over the study period to account for factors that may increase costs (e.g. higher labor or technology costs as programs increased demand for specific services and/or equipment drives up prices) or decrease costs (e.g. lower program implementation costs as programs mature and become more efficient or employ new delivery strategies). For example, utilities have historically placed emphasis on creating cost-effective lighting programs as this is where the majority of savings were found. However, as lighting savings decrease, utilities will likely begin focusing more on programs offering non-lighting savings, which will impact program implementation effectiveness and costs relative to current implementation practices today.

- **The program scenarios are not optimized for program spending.** For each achievable scenario in the DEEP model, incentives levels are set at the program level as a portion of the incremental costs for each eligible measure in the program. However, a real-world program design would likely set unique incentive levels for each measure, applying higher incentive levels for measures that may have had limited uptake in the past, and maintaining or lowering incentive levels for measures that meet their expected adoption. The text box below describes how a more granular approach to incentive setting could lead to significantly lower program spending at minimal expense of reducing savings.

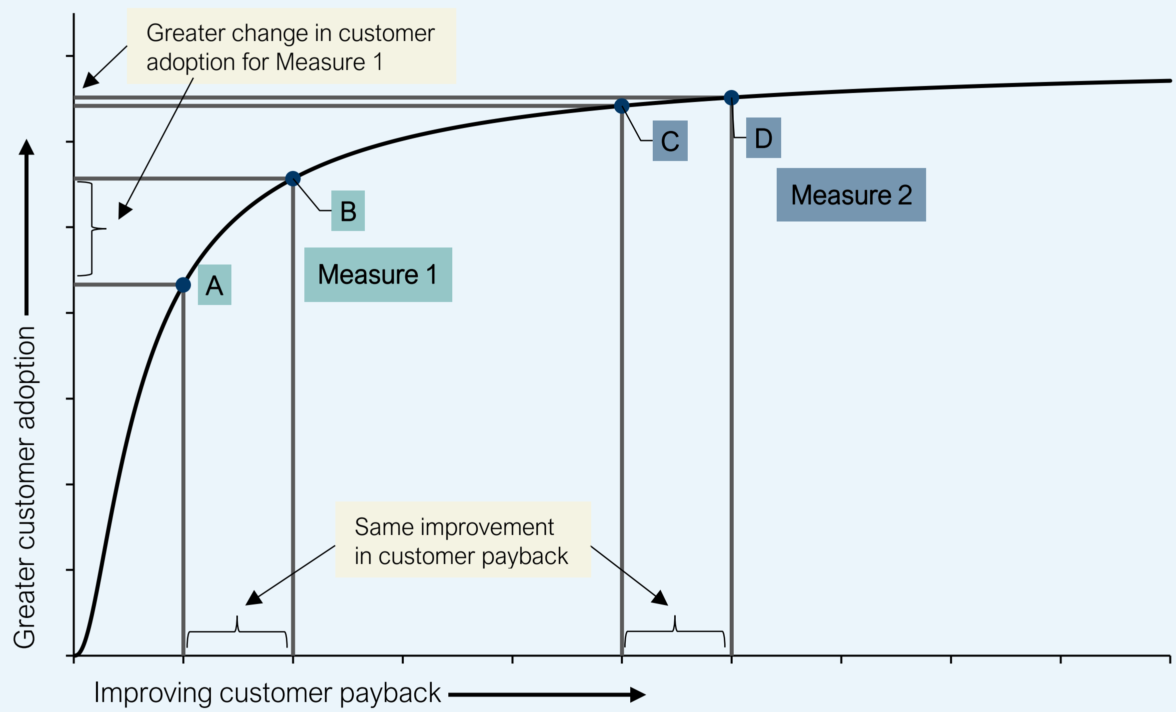
DEEP's Adoption Methodology and Optimizing Program Savings

The DEEP model calculates market adoption as a function of customer payback and a technology's underlying market barrier level. Increasing incentives will improve the customer payback, pushing a measure further to the right along the adoption curve. However, because the adoption curve is not linear, the degree of market reaction will depend on where the measure sits on its allocated adoption curve. This means increasing incentives for measures on the lower end of the adoption curve will result in much greater proportional increase in adoption compared to measures at the higher end of the adoption curve.

Figure 2-27 illustrates this effect. In this example, consider two theoretical measures, Measure 1 and Measure 2. Both are offered within the same program and share the same barrier level assignment, meaning they follow the same adoption curve. Due to differences in the relationship between the incremental costs and the energy savings of the two measures, each sits at a different point on the adoption curve. Measure 1 starts at point A, indicating that the customer payback is not sufficient to drive the majority of potential customers to adopt this technology. Measure 2 has a much higher ratio of energy savings to incremental costs, and thus it sits at point C, wherein most customers will likely adopt the efficient option.

As incentives are increased for both measures, the customer payback is increased, and moving both measures up and to the right along the adoption curve (to Points B and D for Measures 1 and 2, respectively). As can be seen from the figure, this results in a significant increase in adoption for measure 1, which is in the steep part of the adoption curve. However, for Measure 2 the incremental change in adoption is minimal, despite the increased incentives. Ideally, an optimized program design would target Measure 1 for an increased incentive but may not change incentive levels for Measure 2 and would prioritize driving incremental savings from Measure 2 through enabling strategies, marketing, and/or novel delivery pathways rather than through additional incentives.

Figure 2-27. Schematic Example of Adoption Theory



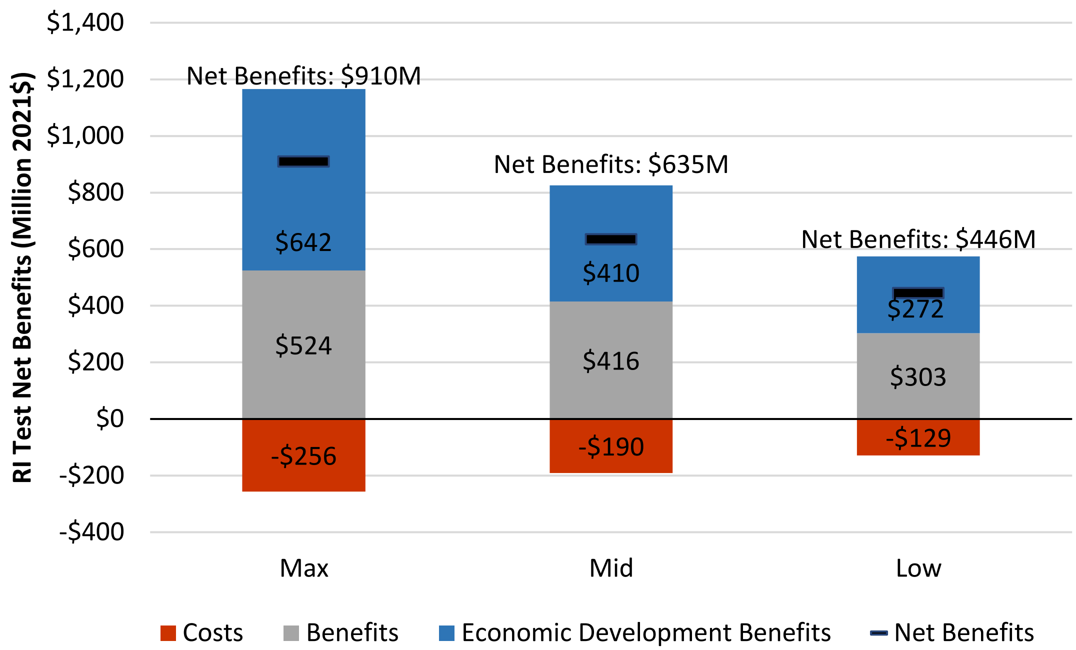
In this study, the impact of this non-linear relationship between incentive costs and savings achievement described above will be particularly pronounced under the Max scenario. Since all measures receive a 100% incentive under the Max scenario, every measure will traverse the higher-end of the adoption curve where incremental increases in incentive payments will induce progressively smaller incremental increases in customer adoption and savings. For this reason, cost estimates under the Max scenario in particular likely significant overstate the cost per unit of savings that could be achieved under an optimized portfolio approach.

2.5.2 Program Benefits

In all scenarios, efficiency savings create significant benefits to rate payers, customers, and society at large. Based on the RI Test, the average lifetime net benefits generated each program year range from $446 million (Low) to $910 million (Max) as shown in Figure 2-28. These benefits include an average addition of $272 (Low) to $642 (Max) million to Rhode Island's state gross domestic product (GDP) resulting from investments in energy efficiency. Even without considering state-level economic benefits, energy efficiency measures deliver significant rate payer benefits through avoiding costs associated with generating electricity; building electricity generation, transmission and distribution capacity; natural gas and delivered fuel delivery; reducing emissions; and other benefits.[36]

[36] For a full description of the costs and benefits included in the RI Test, please see the Attachment 4 - 2020 Rhode Island Test Description as filed with National Grid's 2020 EEPP (Docket No. 4979) accessible at: http://www.ripuc.ri.gov/eventsactions/docket/4979-NGrid-EEPP2020%20(10-15-19).pdf

Figure 2-28. 2021-26 Average Lifetime RI Test Net Benefits Generated Each Year (All Scenarios)



As shown in Table 2-21, all efficiency programs exceed the RI Test threshold of 1.0 across all scenarios.[37] The most cost-effective programs are the residential EnergyStar Lighting and Commercial Lighting programs, which have RI Test ratios as high as 10.4. It is notable, that even the Low-Income programs, which are often the most challenging programs for achieving cost-effectiveness still exceed the RI Test threshold by a significant margin.

[37] Efficiency measures are assigned to programs based on their inclusion in existing programs. For measures currently not offered by existing programs, measures are assigned to the program most likely to offer the measure based on Dunsky's professional judgement.

Table 2-21. Average Program RI Test Benefit-Cost Ratios Including Economic Development Benefits (2021-26; All Scenarios)

Sector	Program	Max	Mid	Low
Residential	Residential New Construction	2.9	2.8	2.9
	EnergyStar HVAC	3.1	3.0	2.9
	EnergyWise	2.5	2.4	2.5
	EnergyWise Multi Family	3.0	2.7	2.8
	Behavior Feedback -- Home Energy Report	2.7	2.7	2.8
	EnergyStar Lighting	10.4	8.2	7.1
	EnergyStar Appliances	4.9	4.7	4.4
Residential Low Income	Low Income Single Family	1.8	1.8	1.9
	Low Income Multi Family	2.9	2.9	2.9
Commercial and Industrial	Commercial New Construction	3.2	2.9	2.8
	Commercial Retrofit	8.8	8.0	8.1
	Direct Install	4.6	4.3	4.4
	C&I Multifamily	5.6	5.4	5.6

The high RI Test ratios are partially attributable to the inclusion of economic development benefits within the RI Test. If economic development benefits are excluded, the vast majority of programs still achieve RI Test ratios above 1.0 – except for the Low Income Single Family program for all scenarios and Commercial New Construction program for the Low and Mid scenarios as shown in Table 2-22.

Table 2-22. Average Program RI Test Benefit-Cost Ratios Excluding Economic Development Benefits (2021-26; All Scenarios)

Sector	Program	Max	Mid	Low
Residential	Residential New Construction	2.0	2.1	2.4
	EnergyStar HVAC	1.9	2.0	2.3
	EnergyWise	1.5	1.6	1.7
	EnergyWise Multi Family	1.5	1.4	1.5
	Behavior Feedback -- Home Energy Report	1.7	1.7	1.7
	EnergyStar Lighting	1.7	1.8	2.0
	EnergyStar Appliances	2.7	2.9	3.1
Residential Low Income	Low Income Single Family	0.8	0.8	0.8
	Low Income Multi Family	1.2	1.2	1.2
Commercial and Industrial	Commercial New Construction	1.0	0.9	0.9
	Commercial Retrofit	3.0	3.3	3.6
	Direct Install	2.2	2.3	2.4
	C&I Multifamily	3.1	3.1	3.3

Efficiency programs also generate significant net bill savings for participating customers. As shown in Figure 2-29, the study estimates efficiency programs will incentivize measures that will generate between

$396 (Low) to $688 (Max) million dollars of net bill savings for customers over the lifetime of the installed measures. The bulk of these customer savings are generated by electric efficiency measures, but natural gas and delivered fuel measures still deliver millions of customer savings each year. Lifetime customer net bill savings are calculated by summing the annual bill savings over the effective lifetime of the measure and subtracting the portion of the measure's incremental cost paid by the customer (e.g. the customer pays 70% of the incremental cost when the utility offers a 30% incentive). It is important to note that this analysis does not account for any changes in retail electricity rates such as increasing system benefit charges (SBC) that would likely be required to fund higher budgets to achieve savings under the Mid and Max scenarios.

Figure 2-29. Lifetime Customer Net Bill Savings Generated Each Year by Fuel Type (2021-26 Average; All Scenarios)

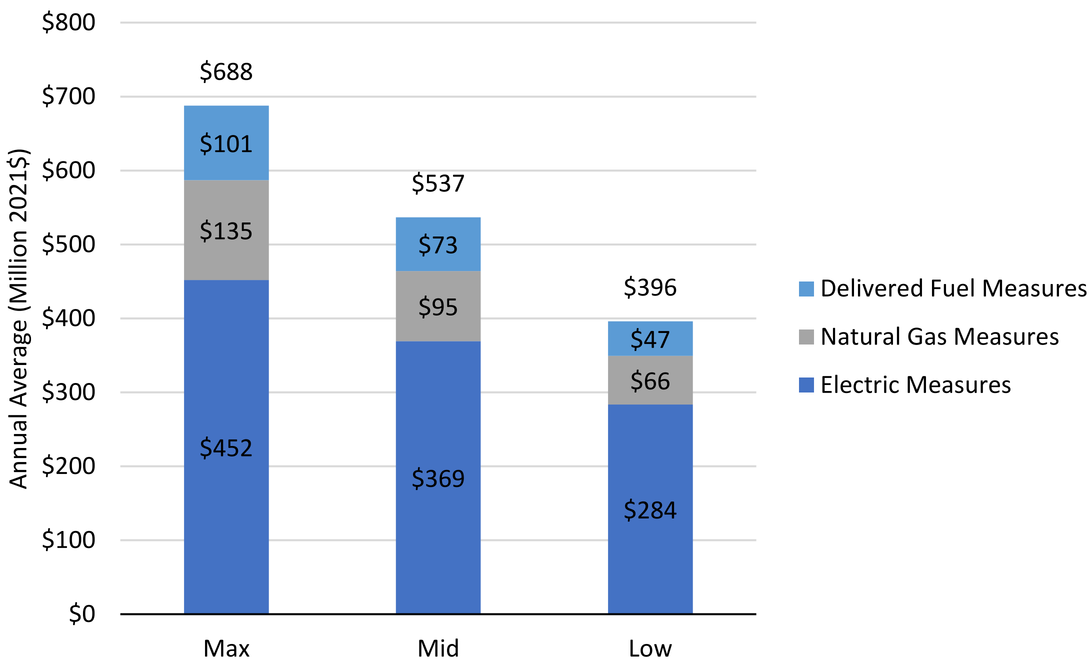


Table 2-23 shows average lifetime customer net bill savings generated each year broken down by sector. As can be seen, the residential and commercial segments experience the bulk of net bill savings, which is commensurate with these sectors' share of efficiency savings.

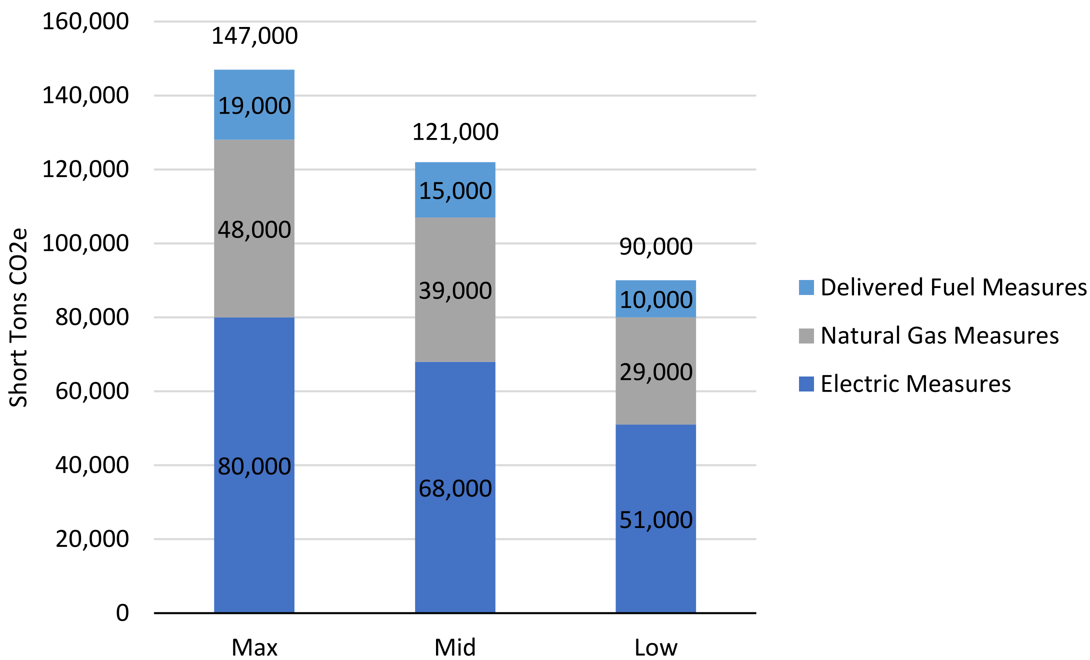
Table 2-23. Lifetime Customer Net Bill Savings Generated Each Year by Sector (2021-26 Average; All Scenarios)

Sector	Max	Mid	Low
Residential	286	193	104
Residential Low Income	19	19	17
Commercial	347	299	254
Industrial	36	26	20
Total	*688*	*537*	*396*

Units: $2021

Finally, the adoption of efficiency measures will also lead to significant greenhouse gas (GHG) emissions reductions. In each year of the study period, efficiency measures are projected to reduce annual emissions by between 90,000 (Low) to 147,000 (Max) short tons of carbon-dioxide equivalent (tCO_2e) on average.[38] To put this in context, efficiency programs could reduce Rhode Island's annual emission footprint by between 539,000 to 879,000 tCO_2e by 2026, which is roughly equivalent to removing 105,000 to 172,000 passenger vehicles from the road for a year.[39] This would decrease Rhode Island's emissions by a further 3.9% to 6.4% relative to the 1990 baseline emission level of 13.8 million tCO_2e.[40]

Figure 2-30. Annual Greenhouse Gas Emissions Reductions Generated Each Year (2021-26 Average; All Scenarios)



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[38] Emission reductions are estimated using emission factors from the *Avoided Energy Supply Components (AESC) in New England: 2018* report. See Appendix F for more details.
[39] Passenger vehicle estimate calculated using the EPA Greenhouse Gas Equivalencies Calculator accessible at: https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator
[40] *2016 Rhode Island Greenhouse Gas Inventory, Draft Version 1*. Accessed at: http://www.dem.ri.gov/programs/air/documents/righginvent16-d.pdf. 1990 baseline of 12.48 million metrics tons of CO_2e converted to short tons at rate of 1.102 short tons per metric ton.

2.6 Sensitivity Analysis

The EE module results are tested against three sensitivity scenarios as described in Table 2-24. Two of the scenarios explore the impact of retail electricity and fuel rates on customer adoption of efficiency measures by increasing/decreasing customer rates by 25%. The remaining scenario tests assumptions made in the study related to the ability to claim specialty bulb savings. Each sensitivity is tested against the Mid scenario, but the impacts under the Low and Max scenarios is expected to be similar in relative magnitude.

Table 2-24. EE Module Sensitivity Descriptions

Sensitivity Scenario	Description
Electricity Rates	Forecasted retail electricity rates are increased/decreased by 25% impacting bill savings associated with electric efficiency measures.
Fuel Rates	Forecasted fuel rates (natural gas and delivered fuels) are increased/decreased by 25% impacting bill savings associated with gas and delivered fuel efficiency measures.
EISA	All savings from specialty and reflector bulbs are removed to simulate the enforcement of the Energy Independence and Security Act (EISA) of 2007 backstop provision beginning in 2020. As of May 2020, the enforcement of this provision has not been implemented by the U.S. federal government and is currently subject to further legal challenges.[41]

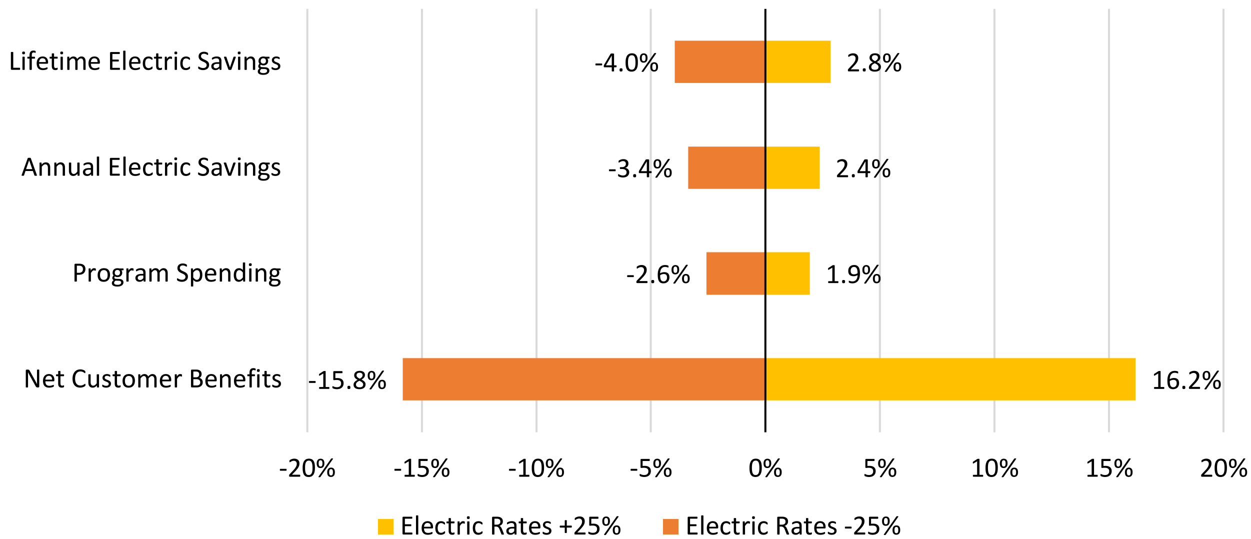
2.6.1 Electric Rates

Higher electricity rates will drive greater participation in efficiency programs, while lower electricity rates will reduce participation. This change is participation is driven entirely by the change in financial attractiveness of efficiency measures for customers due to more (or less) expensive retail electricity rates. The change in retail rates does not change the portion of savings that pass economic screening under the RI Test as avoided cost rates do not vary in this sensitivity analysis.

As shown in Figure 2-31, the proportional impact of varied retail electricity rates is generally greater when rates are lower than forecasted compared to higher rates. There is a larger proportional impact on incremental lifetime savings compared to incremental annual savings indicating measures with longer savings persistence are more sensitive to future electricity rates. Program spending is impacted to a lesser degree than savings due to unavoidable fixed program costs that will be incurred regardless of participation levels. Finally, the increase/reduction in customer participation is much smaller than the relative change in net customer benefits, which illustrates how influential future retail electricity rates are on the customer's value proposition for pursing energy efficiency.

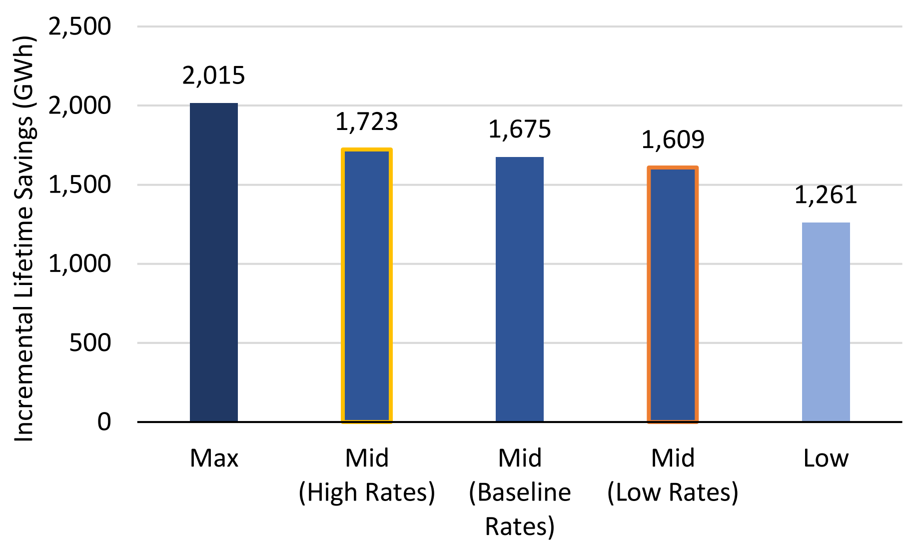
[41] Utility Dive. November 6, 2019. *States, NGOs sue DOE for reversing lightbulb standards as global energy efficiency progress stalls.* Accessible at: https://www.utilitydive.com/news/states-ngos-sue-doe-for-reversing-lightbulb-standards-as-global-energy-eff/566701/

Figure 2-31. Proportional Impact of Electric Rate Sensitivity on Incremental Lifetime Savings, Incremental Annual Savings, Program Spending and Net Customer Benefits as Compared to Baseline (2021-26 Averages; Mid Scenario)



In terms of absolute changes, the higher electricity rate sensitivity increases 2021-2026 average incremental lifetime savings to 1,723 GWh per year and the lower rate sensitivity decreases savings to 1,609 GWh as shown in Figure 2-32.

Figure 2-32. Incremental Lifetime Electric Savings for Mid Scenario under Electric Rate Sensitivity (2021-26 Average)



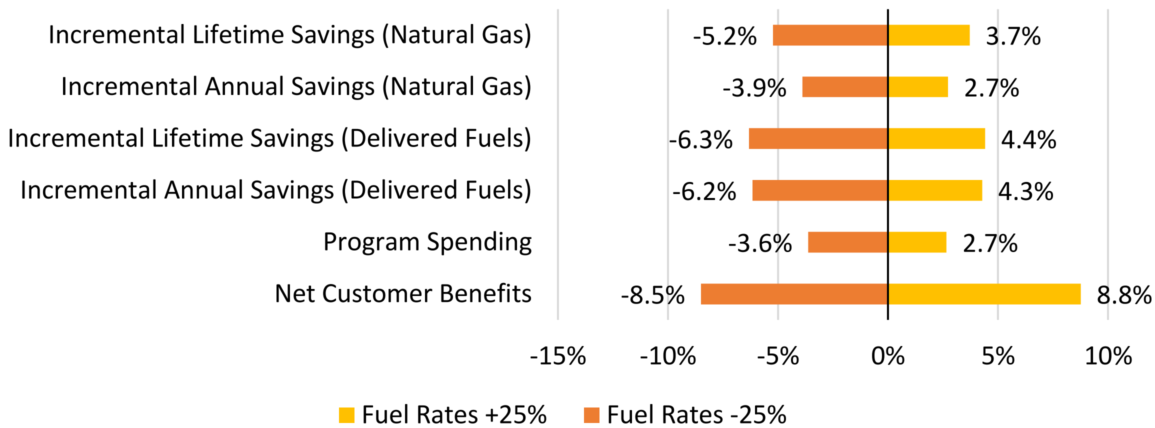
Note: Results for Max and Low scenarios in above figure are under baseline rates and provided for comparison purposes.

2.6.2 Fuel Rates

Similar to retail electricity rates, higher fuel rates will drive greater participation in efficiency programs, while lower fuel rates will reduce participation with a similar pattern of lower rates have a bigger impact on participation than higher rates. Also similar to retail electricity rates, this change is participation is driven entirely by the change in financial attractiveness of efficiency measures for customers due to more (or less) expensive retail gas rates. The change in retail rates does not change the portion of savings that pass economic screening under the RI Test as avoided cost rates do not vary in this sensitivity analysis.

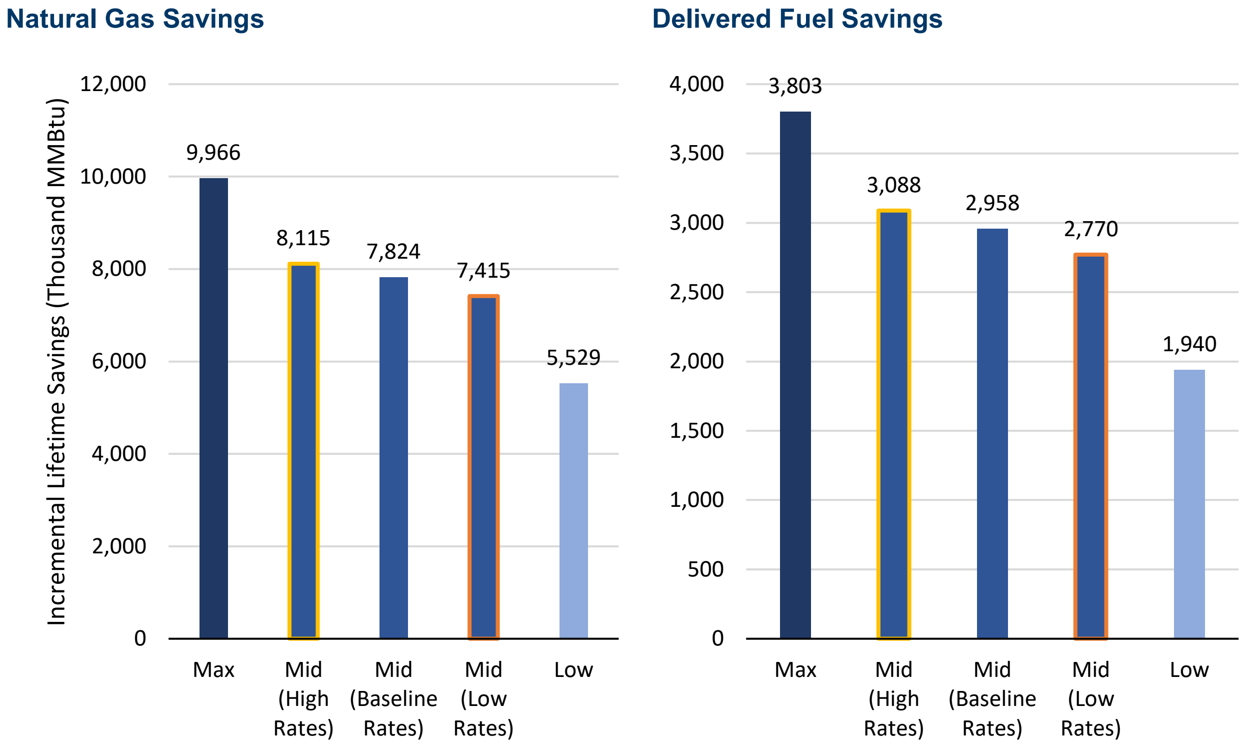
For natural gas savings, fluctuations in fuel rates have a greater impact on incremental lifetime savings relative to incremental annual savings, while this pattern is not evident in delivered fuel savings due to less variance among measure life and savings persistence for the delivered fuel measures that provide the bulk of savings. Like the electricity rate sensitivity, program spending is impacted to a smaller degree than savings due to the impact of fixed program costs, and the proportional impact on net customer benefits exceeds impacts on program savings and spending.

Figure 2-33. Proportional Impact of Electric Rate Sensitivity on Incremental Lifetime Savings, Incremental Annual Savings, Program Spending and Net Customer Benefits as Compared to Baseline (Mid Scenario)



In terms of absolute changes, the higher fuel rate sensitivity increases 2021-2026 average incremental lifetime savings for natural gas to 8,115 thousand MMBtu per year and the lower rate sensitivity decreases savings to 7,415 thousand MMBtu as shown in Figure 2-34.

Figure 2-34. Incremental Lifetime Gas and Delivered Fuel Savings for Mid Scenario under Electric Rate Sensitivity (2021-26 Average)

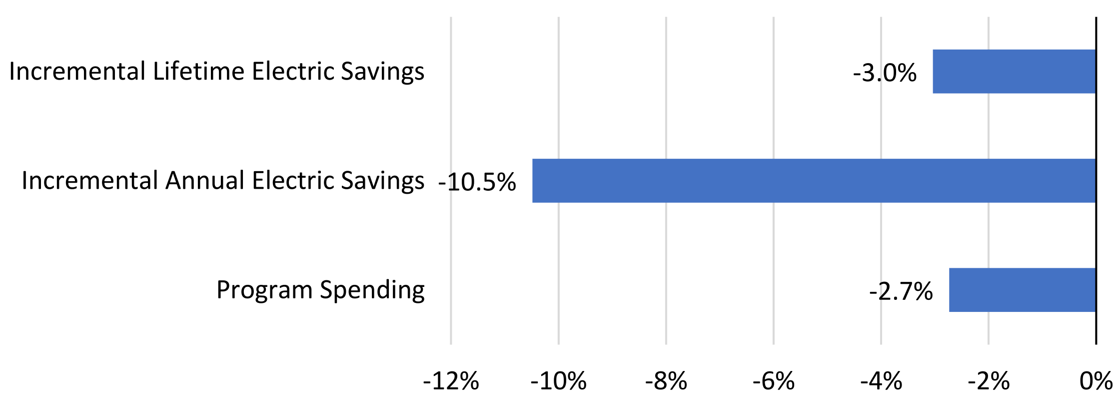


Note: Y-axis scales are not identical between graphs. Results for Max and Low scenarios in above figure are under baseline rates and provided for comparison purposes.

2.6.3 EISA

As can be seen in Figure 2-35, the loss of specialty light bulb savings reduces annual incremental lifetime electric savings by 3% in the first two years of the study, which is approximately 51GWh each year. The impact on incremental annual savings is greater – reducing savings measured in this manner by over 10%. Finally, if programs no longer offer specialty bulb measures, overall program spending can be expected to decrease by approximately 2.7%.

Figure 2-35. Proportional Impact of EISA Sensitivity on Incremental Lifetime Savings, Program Spending and Net Customer Benefits as Compared to Baseline (2021-22 Only; Mid Scenario)



Note: The above figure only shows impacts for the first two years of the study (2021-22) as the remainder of the study period does not include specialty bulb savings under baseline assumptions, thus this sensitivity scenario has no impact during these years.

Advanced Metering Functionality

Though not explicitly modeled under the efficiency module, the deployment of AMF in Rhode Island could play a role enabling greater efficiency savings, and should be considered as one tool among many for reducing customer barriers in order to achieve the savings potentials in the Mid and Max scenarios. The granular usage data made available through AMF can be used to expand and enhance behavioral efficiency measures (e.g. more targeted information in home energy reports, delivering real-time consumption data to customers, high bill alerts, etc.). It can also help program administrators apply targeted marketing and communications providing tailored messaging to customers based on their own consumption profiles. Finally, AMF can provide better evaluation data, enabling more precise quantification of energy savings, or using real-time evaluation to support pay for performance program models - among other applications.[42]

2.7 System Impacts

The following section presents the EE module's results in terms of *cumulative savings* to provide an assessment of system level impacts resulting from efficiency programs. As described in Chapter 1, cumulative savings are a rolling sum of all *new* savings from measures that are incentivized by efficiency programs. Cumulative savings provide the total expected impact on energy sales and electric peak demand overtime and are used to determine the impact of efficiency programs on long-term energy consumption and peak demand.

This section also provides cumulative results for technical and economic potential in addition to achievable scenario potential. There are two key caveats for understanding the technical and economic potential as presented in this section.

First, the **DEEP model estimates all potentials (technical, economic, and achievable) on an annual phased-in basis**. The model assumes that most efficient measures are not eligible for deployment until the existing equipment it is replacing reaches the end of its useful life or becomes a viable early replacement measure. This limits the number of opportunities available for efficiency upgrades each year. For this reason, technical and economic potential will increase each year of the study as more baseline equipment is eligible to be replaced.

Second, **technical potential in the EE module represents all savings from *commercially viable* measures** as opposed to all *technologically possible* savings. As explained further in Appendix A, the efficiency measures included in this study were limited to currently commercially viable options, and those that may become commercially viable over the study period (based on Dunsky's professional experience). In some cases, Dunsky excluded measures that were highly unlikely to pass RI's Cost-Effectiveness Test in the

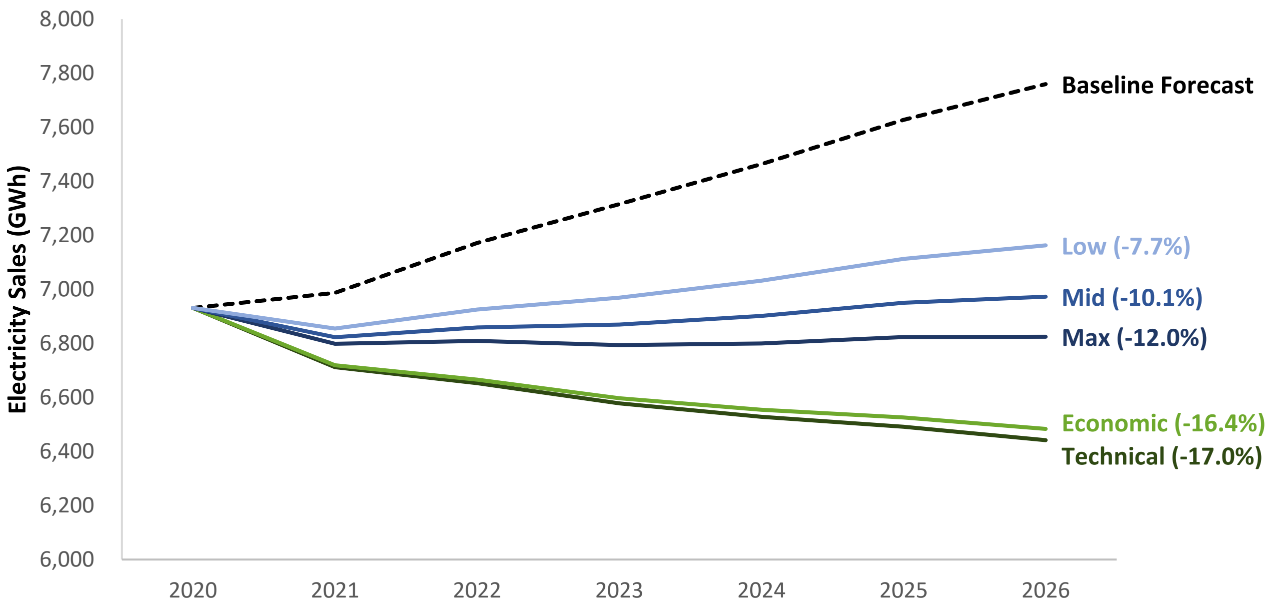
[42] For a full discussion on the potential ways to use AMF to drive efficiency savings, please see: ACEEE, *Leveraging Advanced Metering Infrastructure to Save Energy* (2020).

study period due to relatively low savings and/or high incremental costs or measures that have extremely low market penetration due to existing baselines.

2.7.1 Electricity

By 2026, achievable electric efficiency savings could reduce annual electric consumption by 597 GWh (Low) to 935 GWh (Max). This would reduce annual electricity sales by between 7.7% (Low) and 12.0% (Max) of forecasted levels in 2026 as shown in Figure 2-36. If all economic savings were captured, electricity consumption would decline by approximately 1,276 GWh (16.4% of forecasted 2026 sales), and if all technical savings were captured, electricity consumption would decline by 1,318 GWh (17.0% of sales).

Figure 2-36. Impact of Electric EE Savings on Forecasted Electricity Sales (2021-26; Technical, Economic, and Program Scenarios)



Note: Y-axis in above figure does not begin at zero.

From these results, the following observations can be made:

- **Technical and economic potential are nearly the same.** Cumulative economic potential for electric EE in 2026 is approximately 97% of cumulative technical potential. This result is driven by three factors:
    - As previously described, the initial exclusion of measures that are not currently commercially viable and are not expected to become viable within the study period screens out technologically possible savings that would be unlikely to pass economic screening (see Appendix F for the full measure list).[43] This reduces overall technical potential without reducing economic potential.

[43] Commercial availability and viability of measures was assessed through a review of available secondary sources such as technical resource manuals as well as Dunsky's professional judgment.

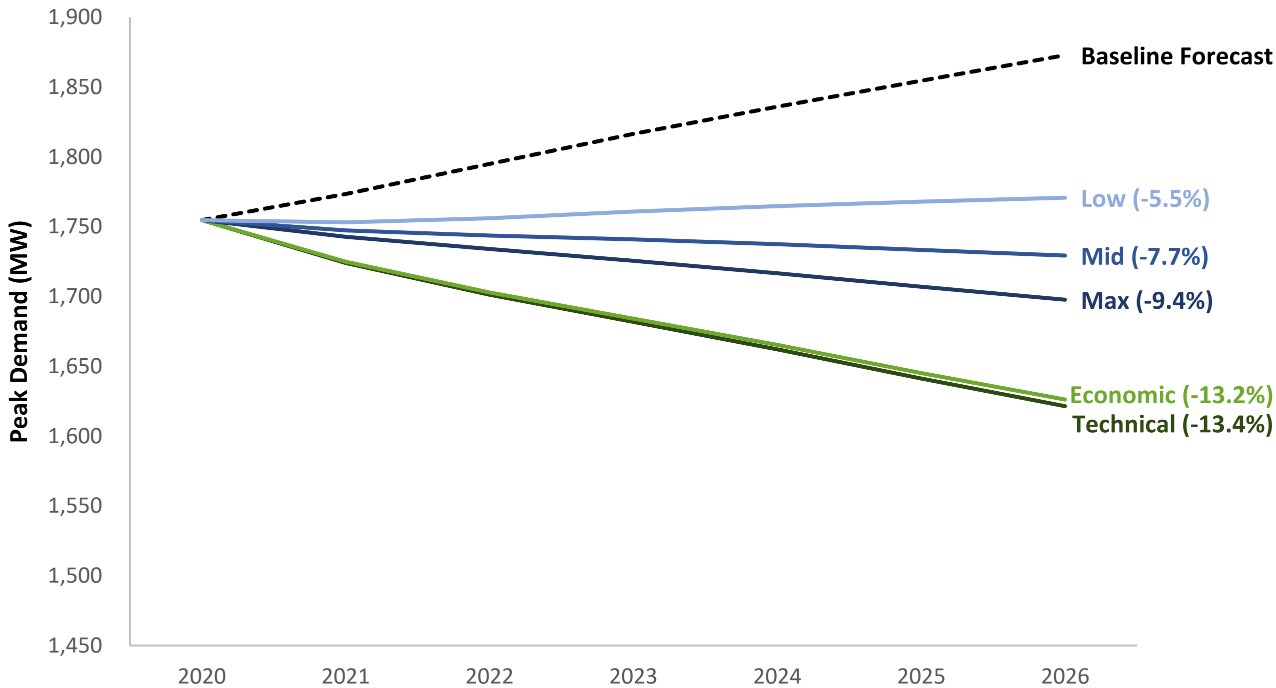
- The study applies an economic potential screen of 0.75 to individual measures – meaning that all measures whose lifetime benefits as quantified by the RI Test are higher than or equal to 75% of the measure's lifetime costs are included in economic potential. This ensures that measures with qualitative benefits that are not explicitly valued in the RI Test are not erroneously excluded. It also allows for marginally cost-effective measures to be combined with other more cost-effective measures for inclusion in efficiency programs as long as the overall portfolio can achieve a RI Test ratio of 1.0 or higher.
- The RI Test provides a full assessment of the value of EE in Rhode Island through the inclusion of a large set of quantifiable benefit streams attributable to efficiency programs beyond what is generally included in conventional efficiency benefit-cost frameworks (e.g. DRIPE[44] and reliability benefits). The inclusion and quantification of these benefit streams ensures efficiency measures are not under-valued and results in additional economic efficiency measures than might be expected under a conventional benefit-cost framework.

- **A significant amount of economic potential can be captured.** The achievable scenarios capture between 47% (Low) and 73% (Max) of economic savings in 2026. This suggests that market barriers for efficient technologies are relatively low. This likely reflects historical efforts in Rhode Island – a state often cited as a leader in energy efficiency – to reduce market barriers for these technologies.
- **Achievable savings are relatively clustered together.** As can be seen in Figure 2-36, there are significant savings potentials under all scenarios, and the spread among the achievable scenarios is relatively narrow. This is due to several factors:
    - In many respects, National Grid's existing EE programs in Rhode Island are best-in-class and already capture a significant amount of EE potential. Since the Low scenario is meant to emulate business-as-usual conditions by applying current incentive levels and barrier reduction activities, the study finds significant electric savings in the Low scenario relative to baseline electric sales.
    - Since many of National Grid's programs are already best-in-class, there are less opportunities to induce additional savings through program enhancements relative to what might be expected in jurisdictions with less advanced efficiency programming. Still, the Mid and Max scenarios represent significant increases in savings over the Low Scenario. By 2026, the Mid and Max scenarios result in 32% to 57% more electric savings, respectively, compared to the Low scenario.

In addition to reducing electricity consumption, EE can reduce statewide peak electric demand through passive peak demand reductions. As shown in Figure 2-37, demand savings under the Low scenario nearly negate any expected growth in peak demand, while the Mid and Max scenarios *reduce* overall peak demand. Like electric consumption savings, technical and economic peak savings potential are similar, and the three program scenarios are clustered together for the same reasons described above.

[44] Demand reduction induced priced effects (DRIPE) refer to the effect a reduction in energy demand can have on energy prices.

Figure 2-37. Impact of Electric EE Passive Demand Savings on Forecasted Peak Demand (2021-26; Technical, Economic, and Program Scenarios)

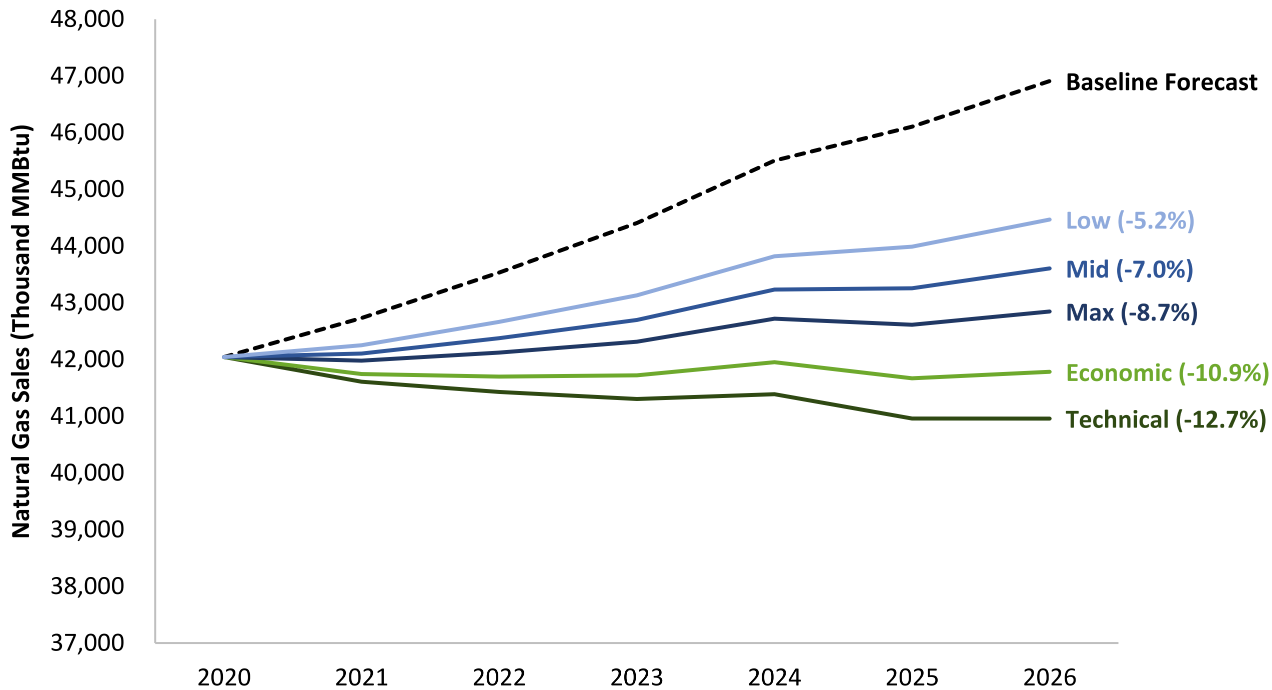


Note: Y-axis in above figure does not begin at zero.

2.7.2 Natural Gas

By 2026, natural gas efficiency programs could reduce annual natural gas consumption by between 2.4 million MMBtu (Low) to 4.1 million MMBtu (Max). This would reduce annual natural gas sales by between 5.2% (Low) and 8.7% (Max) of forecasted levels in 2026 as shown in Figure 2-38. If all economic savings were captured, natural gas consumption would decline by approximately 5.1 million MMBtu (10.9% of sales) and if all technical savings were captured, natural gas consumption would decline by 6.0 million MMBtu (12.7% of sales).

Figure 2-38. Impact of Natural Gas EE Savings on Forecasted Natural Gas Sales (2021-26; Technical, Economic, and Program Achievable Scenarios)



Note: Y-axis in above figure does not begin at zero.

From these results, the following observations can be made:

- **A greater gap exists between technical and economic potential relative to what is observed for electric potential.** While the list for natural gas measures was developed in the same way as electric measures (i.e. only includes commercially viable technologies), the study finds that approximately 86% of technical potential passes economic screening. While still a large portion of technical potential, it contrasts with the 97% of electric technical potential that passes economic screening. The key driver for this difference is the avoided costs attributed to natural gas measures, which are generally much lower compared to electric measures.

  This difference is likely a reflection of two factors. First, the relatively low commodity cost of natural gas translates to lower avoided costs. Based on the values included in the RI Test, the avoided costs of a kilowatt-hour of electricity are roughly three times greater than the avoided costs of an MMBtu of natural gas when compared on an equivalent per MMBtu basis. And second, the RI Test does not include benefits for avoided natural gas infrastructure resulting from reducing peak natural gas demand similar to electric infrastructure. This only adds to the difference in avoided cost benefit streams. With much lower avoided costs, it is more likely that natural gas measures will not achieve a RI Test benefit-cost ratio of 0.75 or greater and thus be excluded from economic potential.

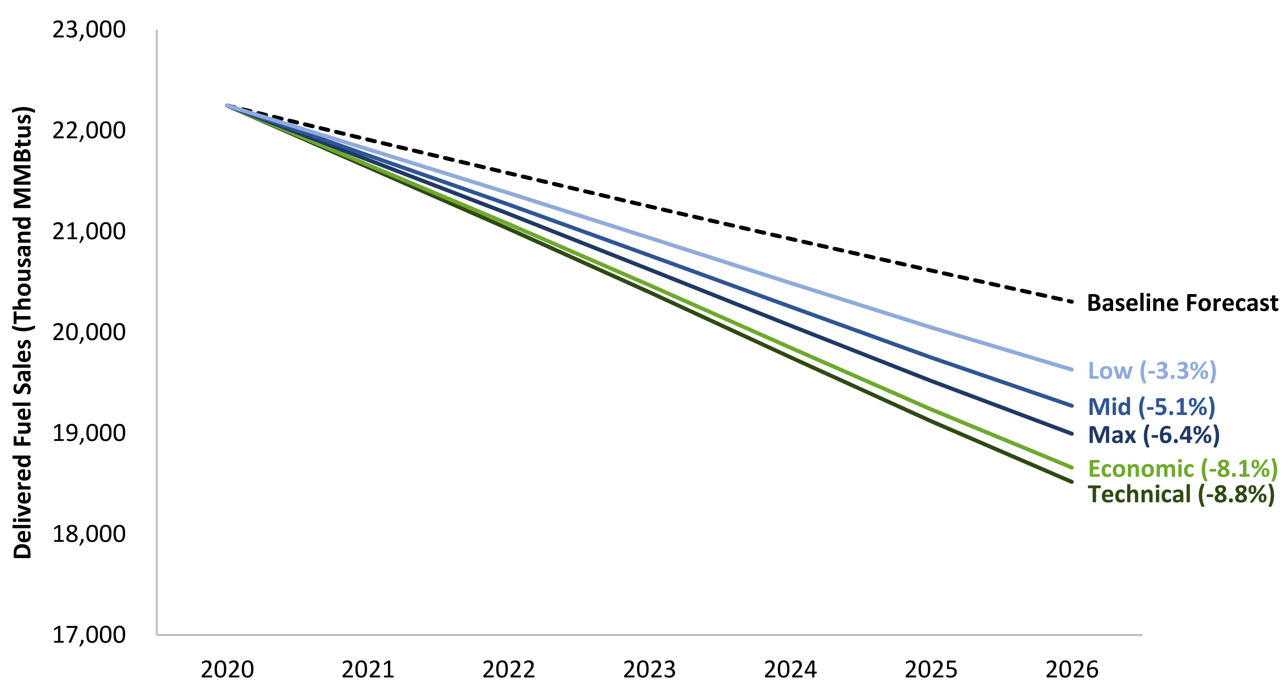
  Still, it is notable that a large majority of natural gas technical potential passes economic screening. It is also important to note that the gap between technical and economic savings is not entirely attributable to gas measures failing economic screening across all segments. In many instances, gas measures fail to pass economic screening in only a portion of segments suggesting that some gas measures are cost-effective in specific segments where savings may be greater due to different use intensities or other factors. For gas savings, approximately 23% of technical savings that do not pass economic screening are from measures that pass economic screening in at least some building segments.

- **A significant amount of economic potential can be captured.** Similar to electric efficiency savings, the study estimates that a large portion of economic natural gas savings can be achieved with between 48% (Low) and 79% (Max) captured in the program scenarios. And also similar to electric efficiency savings, this likely reflects historical efforts in Rhode Island – a state often cited as a leader in energy efficiency – to reduce market barriers for these technologies.

2.7.3 Delivered Fuels

By 2026, delivered fuel efficiency programs could hasten the decline in delivered fuel sales by reducing delivered fuel consumption by approximately 670 thousand MMBtu (Low) to 1,300 thousand MMBtu (Max). This would reduce annual delivered fuel sales by between 3.3% and 6.4%, respectively, as shown in Figure 2-39. If all economic savings were captured, delivered fuel consumption would decline by approximately 1,640 thousand MMBtu (8.1% of sales), and if all technical savings were captured, delivered fuel consumption would decline by 1,790 thousand MMBtu (8.8% of sales).

Figure 2-39. Impact of Delivered Fuel EE Savings on Forecasted Delivered Fuel Sales (2021-26; Technical, Economic, and All Achievable Scenarios)



Note: Y-axis in above figure does not begin at zero.

From these results, the following observations can be made:

- **Technical and economic potential are nearly the same.** Cumulative economic potential for delivered fuel EE in 2026 is approximately 92% of cumulative technical potential. This mirrors the relationship between electric efficiency technical and economic potential, while contrasting with natural gas efficiency potential. The contrast with natural gas potential can be attributed to the generally higher per

MMBtu cost of oil and propane relative to natural gas as well as larger emission benefits associated with delivered fuel savings (a benefit that is quantified in the RI Test).

- **The spread between the Max Achievable and Economic potentials is quite narrow.** Max Achievable is approximately 79% of Economic potential. This relative difference is smaller than electric measures (73% of Economic potential) and similar to gas measures (80% of Economic potential). This suggests that the market barriers to adoption of efficient delivered fuels equipment are less significant than for electric measures, which suggests that the delivered fuel measures included in this study are more established in the market (and thus have lower barrier levels) than electric measures on aggregate..

2.8 Key Takeaways

Based on the results presented in this chapter, the following key take-aways emerge:

Rhode Island has the potential to capture a significant portion of cost-effective efficiency savings over the study period leading to substantial economic and environmental benefits. For all fuel types, the Max scenario captures between 73% to 80% of all economic savings opportunities. These savings can generate up to $910 million in net lifetime benefits for Rhode Island each year, which includes $642 million in economic development benefits. These efficiency savings will also generate up to $688 million in lifetime customer bill savings and 879,000 tCO_2e of emission reductions each year.

Achieving this level of savings however will likely require updating some programs and strategies as many of the residential lighting opportunities leave the market and new opportunities emerge. The study estimates that achieving these savings could carry significant program costs – reaching approximately $300 million per year – although the study applied historical program costs and delivery approaches and did not include an attempt to optimize program designs around cost.

The opportunity exists to maintain substantial incremental annual savings, and grow incremental lifetime savings for electric efficiency programs, even as a large portion of lighting savings leave the market. The loss of claimable savings from A-Lamps and specialty bulbs will significantly reduce lighting program savings – especially in terms of incremental annual savings. However, by investing in new measures, higher incentives, and further enabling strategies, more electric savings can be captured other end-uses. In particular, increasing the adoption of measures with longer useful lives and savings persistence will more than make up for the loss of lighting savings when savings are measured in terms of incremental lifetime savings.

Natural gas savings will grow in importance in the energy efficiency portfolio. As natural gas consumption continues to increase in Rhode Island, so will the opportunity for efficiency savings. The study estimates there is continued room for savings growth – even under business-as-usual conditions.

The opportunity for growing savings is particularly pronounced in the residential sector. While there is the potential for savings growth in all sectors, the relative opportunity for growth of saving potential is much larger in the residential sector between business-as-usual conditions (i.e. the Low scenario) and Mid/Max compared to other sectors. For electric measures, residential savings increase by 79% to 134% under the

Mid and Max scenarios relative to the Low scenario, respectively. For gas measures, residential savings increase by over 100% to 200% under the Mid and Max scenarios, respectively.

3 Demand Response

3.1 Overview

The following chapter presents results for the demand response (DR) module of the market potential study (MPS). The active peak demand reduction potential, herein referred to as DR potential, is assessed by analyzing the ability for behavioral measures, equipment controls and industrial and commercial curtailment to reduce the system wide annual peak demand.[45] A sensitivity of these results to the possible roll out of advanced metering functionality (AMF) by 2024 is also included in the study.

The DR potential is assessed against National Grid's system hourly load curve and annual peak demand.[46] A standard peak day 24-hour load curve is identified and adjusted to account for projected load growth, efficiency program impacts and solar PV installations over the study period. The DR potential is assessed against five years of historical annual hourly load data to simulate year-long measure deployment.

Technical potential is estimated as the total possible coincident peak load reduction for each individual measure multiplied by the saturation of the measure or opportunity in each market segment.

Economic potential is estimated as the net demand reduction possible from each individual measure when assessed against the utility load curve. It accounts for the difference between the utility peak load before and after the measure is applied, when examining the 24-hour peak day curve and the 8,760 annual hourly curve, accounting for individual measure bounce-back impacts or peak time shift impacts. The measures are then screened against the RI Test, and only those that pass the threshold are retained for inclusion in the achievable potential scenarios. [47]

Achievable potential is assessed under three scenarios by applying mixes of all cost-effective measures and programs, giving priority to the most cost-effective measures first. For each year, the DR potential is assessed accounting for existing programs from previous years, as well as new measures or programs starting in that year. Unlike many efficiency measures, the DR peak savings only persist as long as the program is active. For new and expanded programs, ramp-up factors were applied to account for the time required to recruit participants.

Because DR measures interact via their effects on the utility load curve, technical and economic DR potentials are not considered to be additive and are therefore not presented in aggregate in this report. To ensure that the combined achievable potential results were truly additive in their ability to reduce annual peak loads, combinations of programs were assessed against the hourly load curve to capture inter-

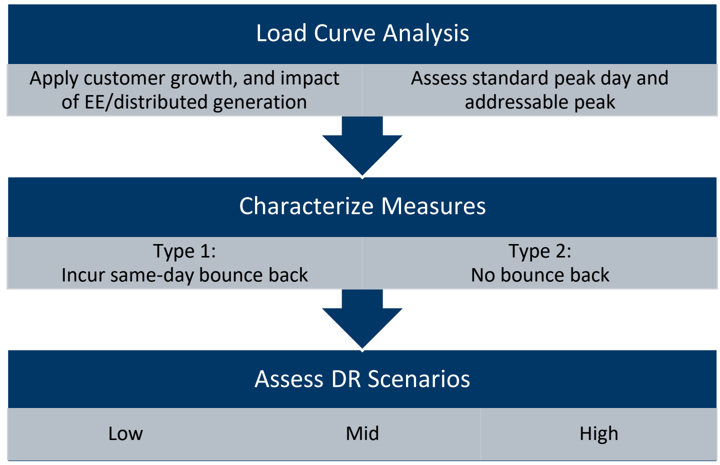
[45] In all cases in this report, the annual peak demand refers to the hour in the year that exhibits the highest system peak demand in MW. It is assessed on a system-wide basis, not accounting for local constraints across the transmission and distribution system.
[46] The impacts of DR programs on the ISO New England load curve are not covered in this study.
[47] For a full description of the costs and benefits included in the RI Test, please see the Attachment 4 - 2020 Rhode Island Test Description as filed with National Grid's 2020 EEPP (Docket No. 4979) accessible at: http://www.ripuc.ri.gov/eventsactions/docket/4979-NGrid-EEPP2020%20(10-15-19).pdf

program interactions that could affect the net impact of each program. Further details of this approach are provided in Appendix C.

3.1.1 Approach

Figure 3-1 below presents an overview of the steps applied to assess the DR potential in this study. Key to this assessment is the treatment and consideration of National Grid's system peak-day hourly load curve, as well as historical full year (8,760 hourly) load curves. This allows the model to assess each measure's net reduction in the annual peak, taking into account that the new annual peak may occur on a different day or hour than the initial peak due to the way that DR measures alter the utility load curve.

Figure 3-1. Demand Response Potential Assessment Approach



In some cases this may lead to results that are contrary to initial expectations, especially when DR programs such as dynamic rates or equipment direct load control (DLC) measures are looked at only from the perspective of how they may impact individual customer peak loads at the originally identified peak hour. **A more detailed description of the DR modeling approach applied in this study can be found in Appendix C.**

3.1.2 Program Scenarios

The achievable potential is assessed under three scenarios corresponding to varied DR approaches or strategies. These scenarios deliver varying benefits covering a range of peak demand impacts. Further details on the specific programs and the related inputs modeled for each scenario are presented in Appendix F.

Figure 3-2. DR Module Program Scenario Descriptions

Low	Applies National Grid's current DR programs and incentive levels, allowing them to expand to their full extent across the applicable market. This provides a **business as usual** case.
Mid	Applies an **expanded list of DR measures and programs,** adding new equipment controls measures, either through utility direct load control, or manual controls, in addition to current curtailment programs.
Max	Applies the expanded list of DR measures and programs, but with **incentives increased to the maximum feasible level** to maintain measure-level cost-effectiveness.

3.1.3 Summary of Results

Under the Low scenario, which represents National Grid's current programs expanded to their full extent, the potential is estimated to grow from 22MW in 2021 to 33MW in 2026, which represents 1.7% of National Grid's peak in 2026. Under the Mid and Max scenarios, the achievable potential estimates respectively achieve 67MW and 84MW in 2026, translating into 3.6% and 4.5% of National Grid's peak. Based on these results, the scenario analysis indicates that expanding the number and types of DR programs and measures can provide more DR potential than simply expanding current programs.

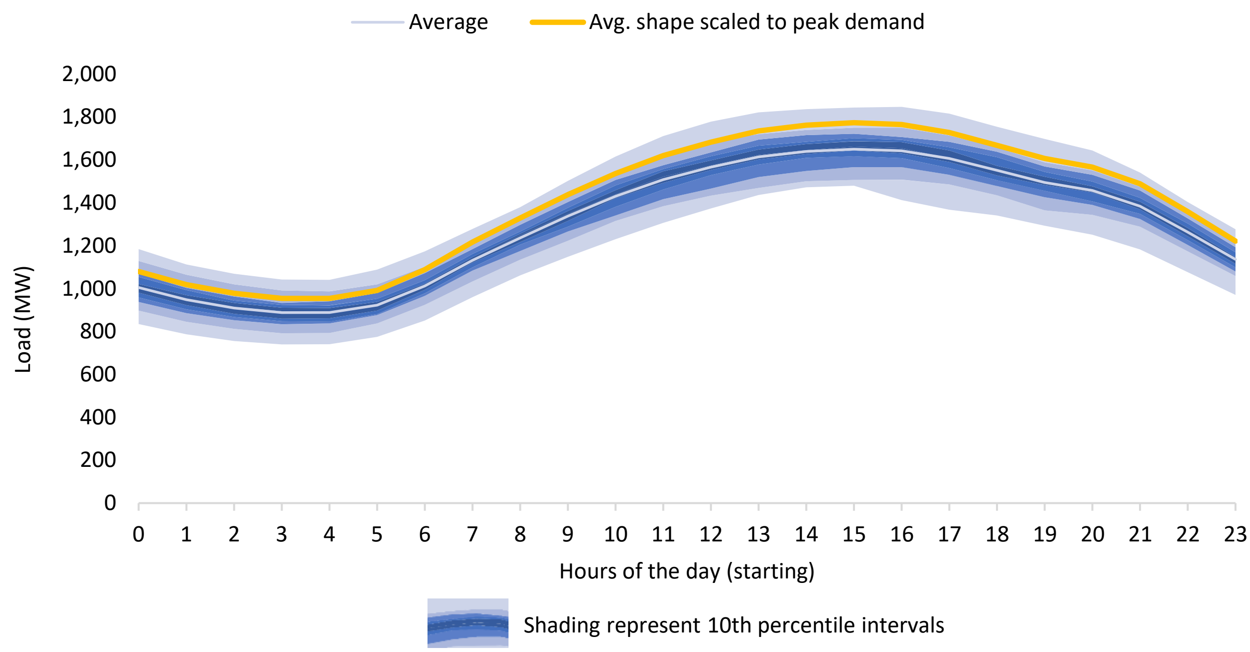
Program spending is projected to range between $1.7 to $2.6 million per year under the Low Scenario, reaching as high as $22 million in the Max scenario. In all scenarios, the results show significant up-front costs in the initial years as new customers are enrolled in the programs and new controls systems are put in place, followed by a greater emphasis in the later years on incentives to maintain participation in the programs. While the Max scenario provides the most peak reduction potential, the Mid and Low scenarios are more cost effective. It is worth noting however, that the Max scenario is more cost-effective than the savings to costs results appear to suggest due to is heavy emphasis on commercial sector programs, which have significantly higher associated economic benefits in the RI Test treatment.

3.2 Load Curve Analysis

The first step in the DR potential analysis is to define the standard peak day load curve and apply the impacts of load growth projections, efficiency measure adoption, and distributed solar PV installations. The standard peak day utility load curve is then used to characterize measures and assess the measure-specific peak demand reduction potentials at the technical and economic potential levels. Achievable peak demand reduction potentials are further verified against five-years of National Grid annual historical hourly load data to assess DR measure deployment constraints and intra-day shifts in the annual peak.

The standard peak day load curve for the electric system is defined by taking an average of the load shape from each of the top ten peak days in each of five years of historical hourly load data provided (Figure 3-3). The shape of the peak day is then maintained over the study period, but the curve is then raised such that the daily peak is equal National Grid's projected annual peak in each of the study years (2021-2026). The curve is then adjusted to account for efficiency measures, distributed solar PV adoption, EV adoption and heating electrification, resulting in the peak day characteristics listed in Table 3-1 below.

Figure 3-3. Standard Peak Day Based on Historical Data – 2020



This analysis finds that National Grid's system has an extended late afternoon peak, which is driven predominantly by residential and commercial space cooling. The duration and steepness of the peak curve indicate that measures with significant bounce-back or pre-charge effects close to the peak will likely have limited potential to reduce the annual peak, as they risk creating new peaks by shifting load from one hour to another. Table 3-1 provides key metrics to describe the peak day shape from a DR potential perspective. It is notable that a gradual shift occurs in the shape and timing of the afternoon peak due to the combined effect of distributed solar PV and EV adoption. Solar PV reduces demand in the summer afternoons, while growing EV adoption increase evening demand, leading to a gradually steepening peak occurring later in the afternoon and evening as the study period progresses. Further details on this trend are provided in Appendix G.

Table 3-1. Standard Peak Day Key Metrics[48]

Year	Peak Demand (MW)	Peak hours	Peak to Average Difference	Peak to Average Ratio
2014	1,653	13:00 – 17:59	349 MW	1.27
2015	1,738	13:00 – 17:59	382 MW	1.26
2016	1,803	13:00 – 17:59	384 MW	1.27
2017	1,688	13:00 – 17:59	363 MW	1.27
2018	1,847	13:00 – 17:59	387 MW	1.26
2021	1,753	13:00 – 17:59	373 MW	1.27
2022	1,748	13:00 – 17:59	372 MW	1.27
2023	1,752	14:00 – 18:59	374 MW	1.27
2024	1,750	14:00 – 18:59	376 MW	1.27
2026	1,744	14:00 – 18:59	378 MW	1.28
2026	1,746	14:00 – 18:59	381 MW	1.28

3.3 Technical and Economic Potential

The analysis applies a range of new and existing DR programs, assessing the ability of each to address the annual peak. A description of each individual program assessed follows. More details on the specific measures and input assumptions can be found in Appendix F.

It is important to note that in this section the technical and economic potentials are assessed for each measure individually, and no interactions among the measures are considered. The following technical and economic potential results provide the DR potential of each measure, across all applicable segments, including currently enrolled demand reduction capacity. Detailed results, by individual measure in each market segment are provided in Appendix G.

Measures that cost-effectively deliver sufficient peak load reductions individually are retained and applied in the achievable potential scenario analysis to determine their achievable potential when interacting with other programs and measure combinations, the results of which are presented later in this chapter. Consistent with the other savings modules in this study, only cases where the measure yields an RI Test value in excess of 0.75 are retained in the economic potential. In all cases RI Test values presented here are those associated with the specific installation year indicated, covering just the market segments that yield RI Test values that exceed the 0.75 threshold.

[48] Historical hourly load data for the years 2014-2018 (shaded rows) was provided by National Grid. 2019 and 2020 values were not available at the time this study was produced.

Annual Peak Assessment vs Target Peak Hour Assessments of DR Impacts

This study measures the potential for each measure, program and portfolio to reduce annual peak hour demand. It considers how reducing loads during the current peak hour can lead to a new peak hour arising outside of the DR event window. The “net” peak load reduction is then assessed as the difference between the original peak demand prior to applying the DR measure and the peak demand at the new peak hour once the measure has been engaged.

This is different than how National Grid assesses peak savings in Rhode Island and leads to somewhat differing values between this report and National Grid’s DR program evaluation and annual performance reports. The difference arises because National Grid reports the impact of DR programs based on their impact during the DR event hours only.

When National Grid’s 2019 DR program enrollments are applied in the DR model used in this study, an overall DR potential of 28 MW is obtained, when expressed in the same DR window impact terms as used by National Grid. This matches closely with the 29.3 MW assessed for the 2019 program evaluation.

	National Grid Reporting (2019)	Modeled DR Window Impacts (2019 Enrolments)[49]	Modelled Annual Peak Impacts (2019 Enrolments)
Residential	5.5 MW	5.8 MW	3.3 MW
C&I Curtailment	29.3 MW	28.6 MW	13.6 MW

For comparison purposes, a table is provided in Appendix G showing DR potentials in 2023 and 2026 under the Low, Mid and Max scenarios, expressed in equivalent DR window impact terms to the DR impact assessment used by National Grid.

[49] 2019 Enrollments and DR impacts from existing curtailment and residential programs were provided by National Grid.

3.3.1 Industrial Programs

National Grid has identified a significant amount of potential through their current industrial and commercial curtailment program. This is comprised of facility load curtailment, as well as self-generation capacity, that can be engaged when a DR event is called by the utility. Table 3-2 presents the technical and economic potential from each industrial sector measure. RI Test results are shown for adding further incremental DR potential over and above currently enrolled program participation, for the year of installation indicated.

Table 3-2. Industrial Self-Generation and Curtailment Potential

Measure	2023			2026		
	Technical Potential (MW)	Economic Potential (MW)	RI Test (2023 installs)	Technical Potential (MW)	Economic Potential (MW)	RI Test (2026 installs)
Battery Energy Storage	0.0	0	-	0.0	0.03	9.0
Large Industrial Curtailment	6.6	6.6	4.5	6.6	6.6	4.5
Medium Industrial Curtailment	2.0	2.0	4.5	2.0	2.0	4.5
Back-Up Generators (Gas only)	0.2	0.2	4.1	0.2	0.2	4.1
Combined Heat and Power (CHP)	0.5	0.5	4.5	0.5	0.5	4.5

A large part of the technical potential and growth is offered by curtailment measures. These measures are assumed to apply a 3-6 hour curtailment window with no demand rebound. Note that there is no new Industrial Curtailment potential growth between 2023 and 2026 as the industrial growth in RI is expected to be limited. Because no details were available regarding the current application of existing CHP systems in National Grid's curtailment program, it was assumed that 50% of the existing systems were available for adding further DR potential, along with all new CHP capacity installed over the study period.[50]

3.3.2 Medium and Large Commercial Programs

National Grid has already enrolled a significant amount of commercial load reduction through their current industrial and commercial curtailment program. This is largely comprised of facility load curtailment, as well as self-generation capacity, that can be engaged when a DR event is called by the utility. Table 3-3 below presents the measures providing a notable degree of peak load reduction.

[50] The CHP DR capacity was determined based on the portion of the system capacity that is not expected to be engaged during system peak hours (late weekday afternoons on July and August weekdays) from an analysis f CHP usage load curves. The expected newly installed CHP capacity over the study period was established based on the business as usual projection (low scenario) in the CHP module of this study.

Table 3-3. Medium and Large Commercial Potential

Measure	2023			2026		
	Technical Potential (MW)	Economic Potential (MW)	RI Test (2023 installs)	Technical Potential (MW)	Economic Potential (MW)	RI Test (2026 installs)
Large Bldg. – HVAC & Other	18.8	18.7	4.3	19.3	19.2	4.3
Medium Bldg. – HVAC & Other	4.9	4.9	4.3	5.0	5.0	4.5
Large Bldg. – Lighting	3.3	3.3	4.3	3.4	3.4	4.3
Medium Bldg. – Lighting	0.8	0.8	4.3	0.8	0.8	4.4
Back-Up Generators	0.9	0.9	4.1	0.9	0.9	4.1
CHP	2.7	2.7	4.5	3.5	3.5	4.6
Large/Med Battery Energy Storage	1.5	1.5	4.5	3.5	3.6	4.7

The HVAC & Other Curtailment measures offer the most technical and economic potential, covering all HVAC measures (setpoint reduction, fresh airflow reduction, etc.) along with other various end-uses and processes (hot water, pumps, etc.). For larger buildings, lighting curtailment can be implemented alongside HVAC system curtailment, applying manual controls at the facility level during DR calls.

3.3.3 Small Business – Equipment Control Program

Small Business Equipment Control measures include Bring-Your-Own-Device (BYOD) and utility Direct Load Control (DLC) measures, similar to the residential sector programs of the same names. These measures were applied just to the portion of each commercial segment that would be considered a small building or premises. Thermal energy storage offers, by far, the most technical and economic potential due to the versatility of the device, which allows it to charge at night during demand troughs.

Table 3-4. Commercial Equipment Control Potential

Measure	2023			2026		
	Technical Potential (MW)	Economic Potential (MW)	RI Test (2023 installs)	Technical Potential (MW)	Economic Potential (MW)	RI Test (2026 installs)
Battery Energy Storage	0.1	0.1	5.1	0.3	0.3	5.0
Thermal Energy Storage	10.1	10.0	1.3	10.2	10.2	1.3
Water Heater	1.2	1.1	2.5	1.1	1.2	2.6
Wi-Fi Thermostat	0.2	0.2	1.2	0.2	0.2	1.3

3.3.4 Residential Programs

Residential programs include the existing behavioral program[51] (assumed to remain unchanged in potential over the study period), as well as a range of existing and new equipment control measures. This includes both Bring-Your-Own-Device (BYOD) and utility provided Direct Load Control (DLC) measures, as listed in Table 3-5 below.

Table 3-5. Residential Equipment Control Potential

Measure	2023			2026		
	Technical Potential (MW)	Economic Potential (MW)	RI Test (2023 installs)	Technical Potential (MW)	Economic Potential (MW)	RI Test (2026 installs)
Behavioral	2.0	2.0	-	2.0	2.0	-
Clothes Dryer	1.6	0.3	1.0	1.3	0.4	0.9
Dehumidifier	0.3	0.3	1.2	0.4	0.4	1.3
Pool Pump	5.5	5.5	2.4	7.8	7.8	2.6
Wi-Fi Thermostat	9.4	7.9	1.9	15.3	9.9	2.5
Ductless HP/AC	0.2	0.2	1.5	0.4	0.3	2.7
Room AC	0.2	0.0	-	0.3	0.0	-
Thermal Energy Storage	60.2	0.0	-	44.7	0.0	-
Battery Energy Storage - BYOD	1.1	1.1	1.4	1.3	1.3	1.5
Water Heater	0.3	0.3	2.6	0.7	0.7	3.5

Most of the economic potential lies in Wi-Fi Thermostat (setpoint control), pool pumps and smart water heaters. While EV load management is the most cost-effective measure, the economic potential is limited by the projected uptake of EVs over the study period. It should be noted however that as EV adoption accelerates, it is expected to amplify the peak and shift it later in the evening, making EV load management ever more important. The BYOD battery storage measure, which leverages solar paired storage, is cost-effective and is retained for consideration in the achievable potential. Similarly, thermal energy storage offers significant technical potential, but does not prove to be cost-effective and is not retained for the achievable potential assessment.

3.4 Achievable Potential

The overall achievable potential in each year for each scenario is presented below (Figure 3-4). These results present the overall peak load reduction potential when all the constituent programs are assessed

[51] The DR behavior program currently entails a media call out asking customers to reduce load on predicted peak days. This program includes no equipment or customer incentives, and no details on program costs or the extent of public outreach were provided. It was therefore assumed that this is a no-cost measure (no RI Test value was calculated) and that the current potential can be maintained, but will not grow over the study period.

together against the utility load curve, accounting for the combined interactions among programs, and reasonable roll out schedules.

Under the Low scenario, which represents National Grid's current programs expanded to their full extent, the potential is estimated to grow from 22MW in 2021 to 33MW in 2026, which represents 1.7% of National Grid's peak in 2026.[52] Under the Mid and Max scenarios, the achievable potential estimates respectively achieve 67MW and 84MW in 2026, translating into 3.6% and 4.5% of National Grid's peak. Based on these results, the scenario analysis indicates that expanding the number and types of DR programs and measures can provide more DR potential than simply expanding current programs.

Figure 3-4. Demand Response Achievable Potential

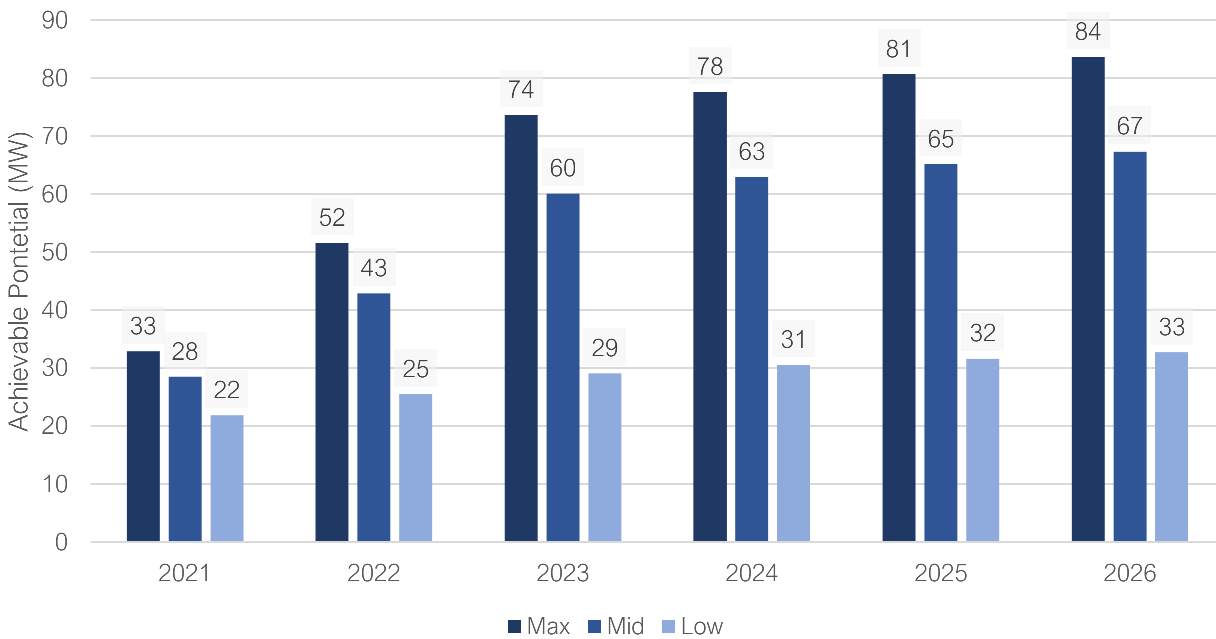


Figure 3-5 below provides the program costs for each scenario, broken down by upfront measure costs[53], and program administration costs and customer incentives. In all scenarios, the results show significant up-front costs in the initial years as new customers are enrolled in the programs and new controls systems are put in place, followed by a greater emphasis in the later years on incentives to maintain participation in the programs.

[52] As noted earlier in this chapter, the DR potentials presented in this report are expressed in terms of the potential under each scenario for the programs to reduce the overall annual peak, accounting for interactions among the programs and measures that may shift the times when peak hours occur. This differs from National Grid's assessment of DR impacts, which consider the ability of the measures to reduce peak loads during the DR event hours only. A table showing the achievable DR potentials expressed in these terms is provided in Appendix G.

[53] Upfront measure costs include sign-up (enrollment) incentive costs, as well as controls and equipment installation costs.

Figure 3-5. Demand Response Program Costs

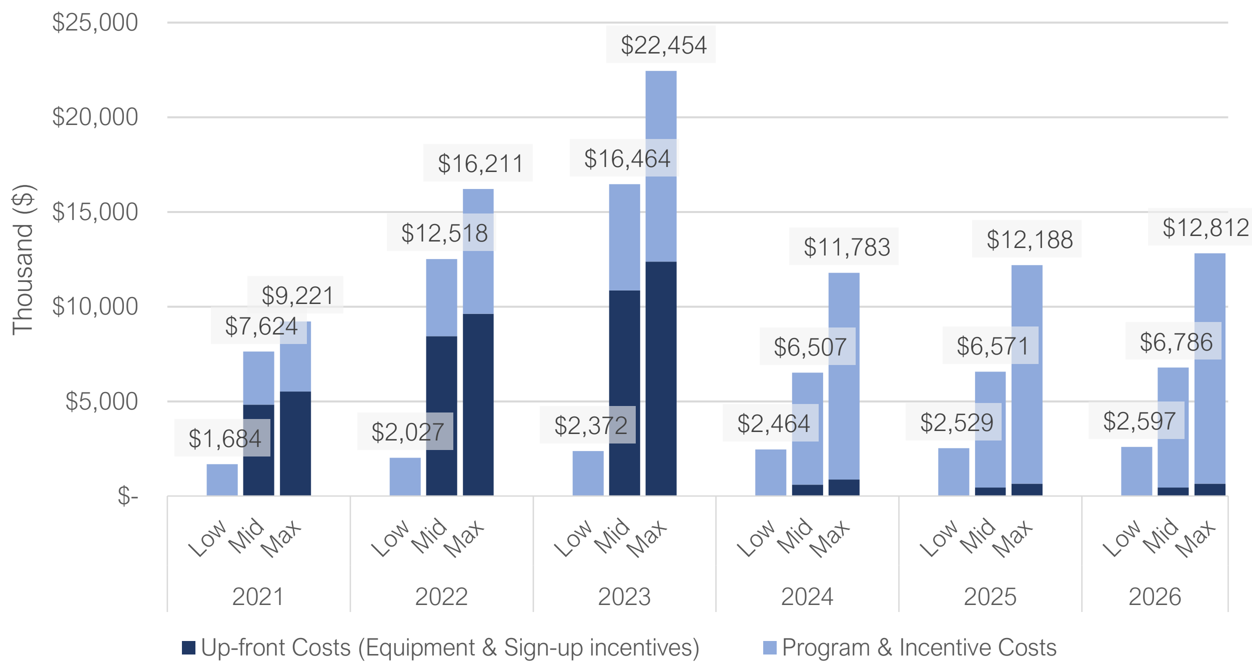


Table 3-6 below provides cost-effective results for each of the three scenarios. The RI Test results include all DR measures that are cost-effective, using a 0.75 benefit cost ratio threshold, assuming a 10-year measure/program life.

Table 3-6. Demand Response RI Test Results

Scenario	2021	2022	2023	2024	2025	2026
Low	4.7	4.6	4.5	4.6	4.6	4.7
Mid	2.6	2.5	2.6	3.7	3.8	3.8
Max	2.4	2.3	2.4	2.8	2.8	2.8

The RI Test results show that while the Max scenario provides the most peak reduction potential, the Mid and Low scenarios are more cost effective. A few key observations to note are:

- **The Low scenario is highly cost effective throughout the study period.** The RI Test values drop somewhat in the later years, as the potential balance shifts toward a greater portion of residential sector demand savings.
- **The Mid scenario shows increasing cost-effectiveness in the later years.** This is because the expanded programs benefit from the upfront cost investments made in the initial years, and just require customer incentives to maintain participation thereafter.
- **The Max scenario is heavy on C&I sector potential which is driven by incentives for self-managed curtailment.** As a result, the RI Test values are supported by high economic benefits for C&I

savings, and do not change significantly over the study period as the program participant mix does not change over the study period.

- **Economic benefits included in the RI Test skew the cost-effectiveness findings.** From a comparison of Figure 3-4 and Figure 3-5 above, it appears that the Max scenario should be less cost effective than the Low and Mid scenario, however in Table 3-6 the RI Test results between Max and Mid are comparable in the initial study years. This is because the RI Test includes economic benefits that are much higher for C&I sector savings ($2.19 per dollar of program spending) than for Residential sector savings ($0.83 per dollar of program spending), thereby increasing the RI Test results for scenarios with greater C&I sector potential, relative to residential sector potential.

Overall, these results show that there is a significant degree of cost-effective DR potential in RI, which could deliver up to 84MW of annual peak reduction, a 67MW increase from the current DR programs.

The achievable potentials were scaled for the local municipal utilities based on the overall customer counts, as per the approach in the other savings modules and the results are provided in Table 3-7 below.

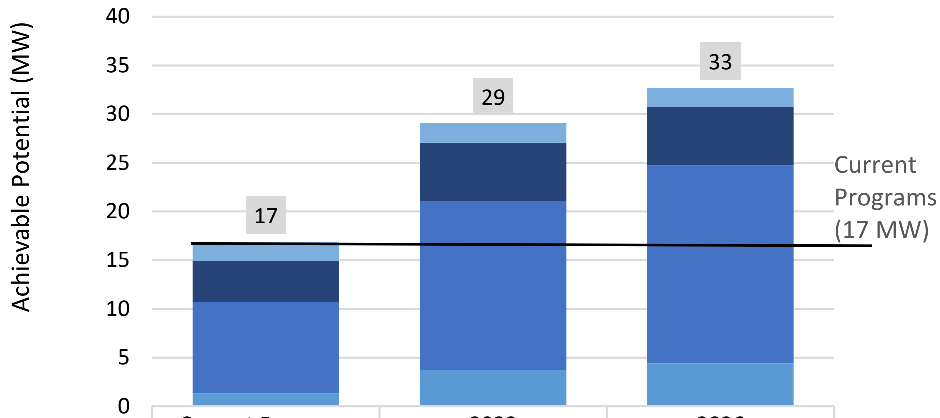
Table 3-7. Demand Response Achievable Potentials

Utility	2023			2026		
	Low	Mid	Max	Low	Mid	Max
National Gird	29	60	74	33	67	84
Pascoag	0.4	0.8	1.0	0.4	0.9	1.1
Block Island	0.3	0.6	0.7	0.4	0.6	0.8

3.4.1 Low Scenario

The Low scenario captures the DR potential from expanding the National Grid existing programs to their fullest extent under the current incentive levels and delivery approach, thereby assessing the uncaptured DR potential still available to these programs. Figure 3-6 below shows that National Grid can achieve nearly twice the current peak demand reductions by 2026 through expanding their existing programs. This comes primarily from an expansion of the commercial and industrial curtailment programs, expanding from 13.6 MW to 26.3 MW in 2026. On the other hand, the residential programs show less room for expansion under their current designs and will mostly grow via expansion of the BYOD battery storage program as solar adoption continues to grow in the state.

Figure 3-6. Low Scenario Achievable Potential by Program



	Current Programs	2023	2026
Total	17	29	33
Residential Behavioral DR	2.0	2.0	2.0
Medium & Large Industrial Curtailment	4.2	6.0	6.0
Medium & Large Commercial Curtailment	9.4	17.4	20.3
Residential BYOD	1.3	3.7	4.4

Table 3-8 below provides the measure-level savings for the current programs, and for the 2023 and 2026 DR potentials. The mid-sized commercial and industrial curtailment measures show the largest potential for growth from their existing levels. These programs tend to be very cost-effective programs, and the cost of expanding these existing programs is much less than the costs of expanding to new measures and programs under the Mid and Max scenarios, which supports higher RI Test values under the Low scenario. Moreover, there is growing potential to enroll installed commercial battery storage capacity in the DR programs as the study progresses.

The Residential BYOD program shows some potential for program expansion, mainly driven by solar paired battery storage. Residential WiFi thermostat also show the potential for growth, but this is somewhat constrained by the limited penetration of central AC systems paired with existing WiFi thermostats in RI homes.

Table 3-8. Low Scenario - Top Measures

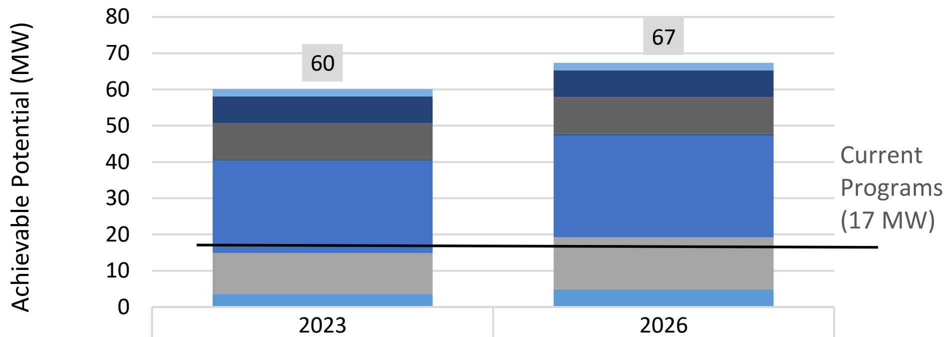
Measures	DR Potential 2019 Enrolment (MW)[54]	Achievable Potential 2023 (MW)	Achievable Potential 2026 (MW)
Large Industrial Curtailment	4.0	4.2	4.2
Medium Industrial Curtailment	0.2	1.8	1.8
Large Comm. Curtailment HVAC & Other	8.6	9.7	9.9
Large Comm. Curtailment Lighting		1.7	1.8
Medium Comm. Curtailment HVAC & Other	0.8	3.8	3.9
Medium Comm. Curtailment Lighting		0.6	0.6
Medium and Large Commercial Battery Storage[55]	0	1.5	4.1
Residential Behavioral DR	2.0	2.0	2.0
Residential WiFi Thermostats	1.3	1.5	1.9
Residential Battery Energy Storage - BYOD	0	2.2	2.5
Total	17	29	33

3.4.2 Mid Scenario

Under the Mid scenario DR programs are expanded to apply new measures and strategies, such as smart pool pumps and EV chargers, capital incentives for energy storage (thermal and battery), and WiFi thermostats for small businesses. As detailed in Figure 3-7 below, the achievable potential increases in nearly all sectors, with commercial curtailment and residential programs driving significantly expanded DR potentials. In this scenario, incentives were increased to match typical values from other jurisdictions for new measures. Where no information was available, the incentives were set to 50% of Max Scenario incentive levels. Details on program settings for each scenario are provided in Appendix F and Appendix G.

[54] Current DR program potentials are assessed in the model using the set of currently supported measures, incentive levels and 2019 enrollment figures provided by National Grid. These are assessed against the hourly load curve to determine their ability to reduce the annual peak. As has been noted this analysis results in differing results than the method used by National Grid that assesses the impact of each program based on its ability to reduce demand during called DR events, regardless as to whether new annual peaks emerge outside of the DR event windows. The DR potential results expressed in these terms is provided in Appendix G.
[55] There is 0.7 MW of new battery capacity planned in the National Grid interconnection cue.

Figure 3-7. Mid Scenario Achievable Potential



	2023	2026
Total	60	67
Residential Behavioral DR	2.0	2.0
Medium & Large Industrial Curtailment	7.4	7.4
Small Commercial DLC	10.0	10.1
Small Commercial BYOD	0.2	0.4
Medium & Large Commercial Curtailment	25.5	28.1
Residential DLC	11.3	14.4
Residential BYOD	3.6	4.9

The top measures under the Mid scenario are provided in Table 3-9 below. The added programs and measures in the Mid scenario generate additional potential, with a few measures offering notable opportunities such as:

- **Residential Pool Pumps and EV Load Management** generate most of the new savings within the Residential DLC program, with 6.3 MW (smart pool pumps) and 1.7 MW (EV load management) by 2026. These two measures provide 8.0 MW out of the 8.7 MW of the Residential DLC program.
- **Battery Energy Storage** in the commercial buildings yields 3.6 MW of new achievable potential by 2026, which is focussed on leveraging customer-owned batteries by adding direct load control from the utility.
- **Medium and Large Commercial Curtailment** offers increased potential through raising incentive levels to attract more participation, an overall increase of 7.8 MW compared to the Low scenario.
- **Lighting measures** in the Medium and Large Commercial Curtailment (3.1 MW in 2026) offer an opportunity for reducing commercial lighting intensities using auto DR controls, where manual reduction of lighting intensities is not practical.

Table 3-9. Mid Scenario – Top Measures

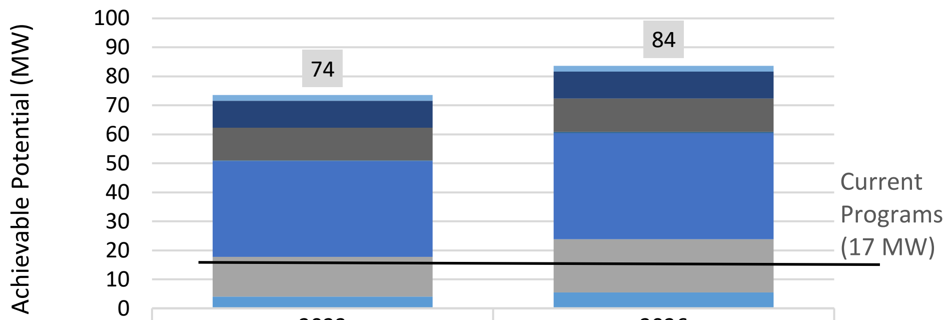
Measures	DR Potential 2019 Enrolment (MW)[56]	Achievable Potential 2023 (MW)	Achievable Potential 2026 (MW)
Large Industrial Curtailment	4.0	5.0	5.0
Medium Industrial Curtailment	0.2	1.8	1.8
Large Comm. Curtailment HVAC & Other	8.6	13.5	13.5
Large Comm. Curtailment Lighting		2.4	2.4
Medium Comm. Curtailment HVAC & Other	0.8	4.4	4.5
Medium Comm. Curtailment Lighting		0.7	0.7
Medium and Large Comm. Battery Storage	0.0	1.5	3.6
Combined Heat and Power (New)	0.0	2.8	3.2
Small Business Thermal Energy Storage (New)	0.0	9.0	9.1
Residential WiFi Thermostats (Expanded to DLC)	1.3	8.1	8.6
Residential Pool Pumps (New)	0.0	4.4	6.3
Residential EV Load Management	0.0	0.5	1.7
Residential Behavioral DRs	2.0	2.0	2.0
Residential Battery Energy Storage - BYOD	0	0.1	0.3

[56] Current DR program potentials are assessed in the model using the set of currently supported measures, incentive levels and 2019 enrollment figures provided by National Grid. These are assessed against the hourly load curve to determine their ability to reduce the annual peak. As has been noted this analysis results in differing results than the method used by National Grid that assesses the impact of each program based on its ability to reduce demand during called DR events, regardless as to whether new annual peaks emerge outside of the DR event windows. The DR potential results expressed in these terms is provided in Appendix G.

3.4.3 Max Scenario

In the Max scenario incentives were increased further, while maintaining individual measure RI Test values of at least 0.75, and portfolio wide RI Test values over 1.0[57]. This leads to more savings in all programs, as shown in Figure 3-8. When compared to the Mid scenario, the Max scenario offers an additional 17MW of potential by 2026. The majority of the gains in achievable potential comes from the medium and large commercial curtailment programs (8.5 MW of additional potential, followed by the Residential DLC program (4 MW of additional potential) and the Medium and Larger Industrial Curtailment (1.9 MW of additional potential) programs. However, as was noted earlier, this increase in potential comes with significantly higher incentive costs, that reduce the overall cost-effectiveness of the Max scenario, relative to the other scenarios.

Figure 3-8. Max Scenario Achievable Potential



	2023	2026
Total	74	84
Residential Behavioral DR	2.0	2.0
Medium & Large Industrial Curtailment	9.3	9.3
Small Commercial DLC	11.3	11.5
Small Commercial BYOD	0.2	0.5
Medium & Large Commercial Curtailment	33.0	36.6
Residential DLC	13.8	18.4
Residential BYOD	4.0	5.4

The resulting top measure mix under the Max scenario is similar to the Mid scenario. However, all measures now have increased potential from increased adoption, resulting from the attractiveness of higher customer incentives. Because industrial and large commercial measures are the most cost-effective (see details in Table 3-2 above), there is more room to increase incentives compared to the other measures, thus industrial measures show the largest increase in potential over the Mid scenario results.

[57] To avoid over stating program budgets, incentives were increased up to a point before they offered little or no additional adoption from further increases, even if higher incentives would still support cost-effective programs.

Table 3-10. Max Scenario - Top 10 Measures

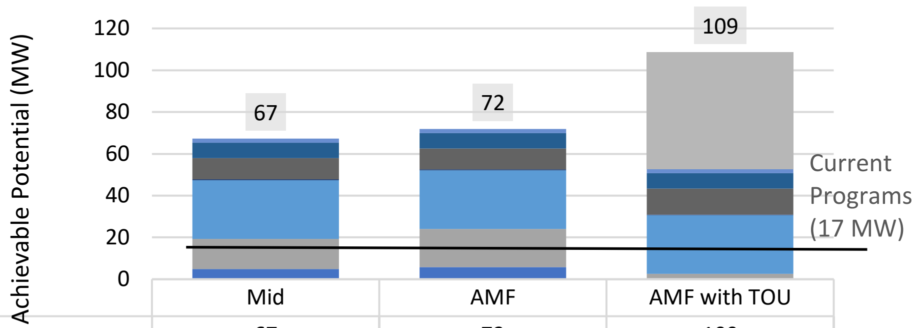
Measures	Current DR Potential (MW)	Achievable Potential 2023 (MW)	Achievable Potential 2026 (MW)
Large Industrial Curtailment	4.0	6.6	6.6
Medium Industrial Curtailment	0.2	2.0	2.0
Large Comm. Curtailment HVAC & Other	8.6	18.8	19.3
Large Comm. Curtailment Lighting		3.3	3.4
Medium Comm. Curtailment HVAC & Other	0.8	4.9	5.0
Medium Comm. Curtailment Lighting		0.8	0.8
Medium and Large Comm. Battery Storage (New)	0.0	1.6	3.6
Combined Heat and Power (New)	0.0	3.2	4.0
Small Business Thermal Energy Storage	0.0	10.0	10.2
Residential WiFi Thermostats (Expanded to DLC)	1.3	9.5	10.2
Residential Pool Pumps (New)	0.0	5.5	7.8
Residential EV Load Management	0.0	0.7	3.1
Residential Behavioral DR	2.0	2.0	2.0
Residential Battery Energy Storage - BYOD	0	0.1	0.3

3.5 Sensitivity Analysis

The sensitivity of the DR potential to the application of Advanced Metering Functionality (AMF) to the Mid scenario achievable potential. This analysis considers the ability of AMF to reduce the controls equipment costs for certain DR measures, and it also considers the impact of AMF to enable time of use (TOU) rates and their effect of DR measure potentials. Because AMF is not currently in place in RI, and AMF is required to enable TOU rates, it is assumed that AMF and TOU impacts would begin in 2024 at the earliest, and thus both sensitivities are applied only to the 2024-2026 period. Further details on the AMF sensitivity inputs and assumptions are provided in Appendix F.

AMF allows communications with DR equipment, there by reducing the initial costs associated with telemetry for some measures. TOU rates on the other hand works to reduce peak demand by sending a price signal to customers, thereby encouraging them to change their behaviour, using less electricity during peak demand hours. This can limit the potential of certain DR measures and programs, DLC programs in particular, as the hourly use patterns of controlled appliances change such that they are less during peak demand periods. Figure 3-9 below presents the results of each sensitivity on the Mid scenario achievable potentials.

Figure 3-9. Sensitivity of the Mid Scenario DR Achievable Potential in 2026 when coupled with AMF and TOU



	Mid	AMF	AMF with TOU
Total	67	72	109
TOU	0	0	56
Residential Behavioral DR	2.0	2.0	2.0
Medium & Large Industrial Curtailment	7.4	7.4	7.4
Small Commercial DLC	10.1	10.0	12.4
Small Commercial BYOD	0.4	0.4	0.3
Medium & Large Commercial Curtailment	28.1	28.0	28.0
Residential DLC	14.4	18.4	2.2
Residential BYOD	4.9	5.8	0.4

The results indicate that AMF roll-out would slightly increase DR potential but could offer greater demand reduction potential increase if TOU rates were put in place to leverage the AMF capabilities.

- **AMF primarily increases the potential from the Residential BYOD and DLC programs** (WiFi thermostats and battery storage). AMF improves the cost-effectiveness of the BYOD and DLC measures, allowing more to pass screening, and causing them to be prioritised over other measures and programs in the model. These measures are added with very little impact to the commercial sector programs, increasing the total potential by 5 MW.

- **TOU rates increase the demand reduction potential by 37MW overall but reduce the DR potential from DLC measures significantly.** The application of TOU rates reduces the annual peak by 56 MW, but it almost entirely replaces the potential from residential BYOD and DLC programs, thereby leading to just a 37MW net reduction in the annual peak, as compared to the Mid scenario. TOU rates encourage behavior changes among residential customers that reduce the effectiveness of appliance and cooling system controls and shift the daily peak to times that are poorly suited to those programs. Commercial and Industrial programs continue to offer notable potential that is complementary to the TOU rates, responding to the newly created early-afternoon peak. The overall demand response potential from this scenario is greater than the Mid and AMF scenarios, with an achievable potential of 109 MW.

Overall, the sensitivities suggest that decisions on where to invest in expanding DR programs should take into consideration the likelihood of adopting TOU rates in the future, as this may impact the effectiveness of certain DR measures, such as the residential DLC measures in particular. In general, the effectiveness of DLC programs would likely be reduced under TOU rates regimes, thereby undermining the value of DLC investments made in prior years.

3.6 Key Takeaways

Based on the results of the DR potential assessment, there is an apparent 67 MW (Mid Scenario) of demand response potential in 2026, representing about 3.6% of the system peak. 17MW of this potential is being captured by current DR program enrollment, which indicates that a further 50 MW of potential is achievable by expanding the expanded program offer modelled under the Mid scenario. Alternatively, the Low scenario suggests that a further 16MW of potential is achievable by expanding participation in existing programs only.

As shown in Table 3-11, the DR achievable potential can be increased further by providing more incentives to drive program adoption, expanding program and by implementing Time-of-Use rates if AMF is pursued.

Table 3-11. Mid scenario compared to the Max and TOU scenarios

Scenarios	Mid Scenario	Max Scenario	TOU + Mid Scenario
Achievable Potential (MW)	67	82	109

Table 3-12 below benchmarks the achievable DR potential from the Mid and Max scenarios to DR potential study findings in other jurisdictions. Overall, these show that the RI DR potential is similar to other summer peaking jurisdictions, where the industrial portion of the utility peak load is moderate, as is the case in RI.

Table 3-12. Benchmarking of the achievable DR Potential (Mid Scenario) to other summer peaking Jurisdictions

	Rhode Island (2020)	Massachusetts (2018)	Michigan (2017)	Northwest Power (2014)
Portion of Peak Load	3.6% - 4.4% (2026)	3.5% - 4.0% (10-year outlook)	2.3%-5.3% (3-year outlook)	8.2% (15-year outlook)
Avoided Costs	$200 / kW	$290 / kW	$140 / kW	n/a

Based on the findings in this report three key take-aways emerge:

- **There is significant opportunity to expand DR programs in RI in a cost-effective manner, both through growing the market for existing programs, and introducing new programs and measures.** Both the Low and Mid scenarios demonstrate notable increase in DR potential over current DR program performance. Most of the potential expansion is concentrated in Wi-Fi Thermostats and Commercial Energy Storage. The first would be an expansion of an existing program, while the second would be a new program with the utility providing a capital incentive for thermal or battery energy storage initial costs.

- **Expanding to new DR programs can generate demand savings more cost-effectively than just increasing incentives.** By 2026 the Mid scenario (expanded with new programs) offers an additional 34MW of potential over the Low scenario (current programs extended over the full market), with the Mid scenario returning a RI Test values of 3.8 compared to the RI Test of 4.7 for the Low scenario. The Max scenario offers a further 17MW of potential, but at a twofold increase in program costs and yielding a reduced RI Test result of 2.8 by 2026.
- **The Rhode Island peak day curve is currently well suited for commercial curtailment, but as solar distributed generation and EV penetration increase, residential sector will become an increasing important source of DR potential.** The current peak occurs in summer afternoons, which is highly coincident with commercial building loads such as cooling and ventilation. Expected changes in demand caused by solar PV and EV adoption will shift the afternoon peak to later in the day, thereby decreasing the coincidence with commercial loads, and increasing the coincidence with residential loads.

Overall, it appears that adding new measures, while expanding the current programs is the best option to optimize the DR achievable potential in Rhode Island.

Design Today's Programs with an Eye to the Future

This study shows that there are a number of emerging trends that are changing the peak day load curve in RI. These include increased adoption of distribute solar PV, EVs, heating electrification, ongoing efficiency programs, and the possible implementation of AMF. As these change the timing and shape of the utility peak, the mix of cost-effective programs will change with time.

While there is much potential to expand on existing DR programs in RI, some programs carry notable upfront investments for enrolling customers and installing controls equipment. When considering new programs, or the expansion of existing programs in RI, those programs should be assessed against the projected load curve shapes for 5 and 10 years into the future to determine which strategies will best fit RI's changing peak management needs. Moreover, investments in residential DLC programs should considered in light of possible TOU rate regimes (enabled by AMF) in the future, as a broad TOU rate application could undermine prior investments in DLC programs.

4 Combined Heat and Power

4.1 Overview

The following chapter presents results for the combined heat and power (CHP) module of the market potential study (MPS). The CHP module estimates the technical, economic, and achievable potential for CHP in Rhode Island.

4.1.1 Summary of Results

The study estimates there is approximately 342 MW of technical potential in terms of installed capacity in Rhode Island. This result represents the amount of CHP that might be expected if all applicable thermal load was supplied by CHP systems regardless of customer economics. When CHP systems are sized with customer payback in mind, only 94MW of the technically feasible capacity is considered economic representing approximately 27% of technical potential (note: technical and economic potential have unique definitions in this chapter relative to the rest of the MPS as described below).

At the segment level, the largest amount of CHP potential is found in the office segment with significant amounts of potential in the manufacturing & industrial, campus & education, and healthcare & hospitals segments. The significant potential in the office segment is a surprising result given historical CHP installations and typical thermal loads of office buildings and may be an artefact of data limitations in the study. Additional market research is needed to validate this finding.

For achievable potential, the study estimates that CHP programs could incentivize 3.5 MW (Low) to 4.5 MW (Mid) of additional installed CHP capacity per year during the study period. Under the Max scenario, CHP adoption significantly increases to approximately 11.1 MW of capacity per year.

4.1.2 Approach

Technical and economic CHP potential is estimated using a bottom-up approach that estimates optimal CHP system sizes on a per customer basis by analyzing monthly gas customer billing data as a proxy for thermal loading.

Technical potential is estimated by sizing CHP systems to cover 100% of the customer's eligible thermal load regardless of customer economics. Eligible thermal load excludes direct-fired heating uses such as cooking or process. In this way, technical potential is a measure of the market size that is only constrained by technological limits – that is, the ability of the technology to match customer thermal needs and does not consider cost or site constraints.

Economic potential is estimated by sizing CHP systems to ensure a RI Test benefit-cost ratio greater than 1 and a reasonable customer payback of at least 9 years. Ultimately, sizing systems to a reasonable customer payback is the limiting factor for system sizes and resulted in systems with RI Test BCRs of approximately 1.5.

Achievable potential is then estimated by applying technology adoption and diffusion theory as captured through the Bass Diffusion Curve.[58] However, due to the relatively small size of the potential market for CHP in Rhode Island and the generally "lumpiness" of CHP investments (i.e. relatively few projects and large variances between project sizes), the application of technology adoption and diffusion theory is limited in estimating a specific year's likely adoption on a segment-by-segment basis. For this reason, the achievable potential for CHP is most appropriately interpreted at an aggregate level over the entire six-year study period across the entire market. Therefore, achievable results are presented as annual averages without specific segment results.

Due to the exclusive use of natural gas customer data, potential estimates are limited to customers with existing natural gas access and natural gas consumption profiles amenable to CHP. Current delivered fuel customers are not considered in the analysis. A full description of the methodology for estimating CHP potential is provided in Appendix D.

4.1.3 Program Scenarios

The CHP module explores three program scenarios as summarized in Figure 4-1.

Figure 4-1. CHP Module Program Scenario Descriptions

Low	Incentives levels are set at the **maximum allowable incentive level of 70%** of project capital costs with adoption barrier levels set to reflect historical adoption in Rhode Island.
Mid	Incentives levels are set at the maximum allowable incentive level of 70% of project capital costs with **adoption barrier levels reductions** to simulate additional market barrier reductions.
Max	**Incentive levels set at 100%** of project capital costs with the same barrier level reductions as the Mid scenario.

It should be noted that due to model imitations, the study's incentive structure does not precisely mirror the incentive structure offered in National Grid's current CHP program, which offers incentives on a net kW basis with per kW incentive amounts varying depending on the overall efficiency of the installed system (higher efficiency systems receive a larger per-kW incentive) and other factors (e.g. whether the customer has implemented energy efficiency measures) and caps payments at 70% of a project's capital costs.[59] In some cases, individual CHP projects will be eligible for incentive amounts that are less than 70% of the project's capital costs – or may even be ineligible for any incentive payments if system efficiency is deemed to be less than 55%.

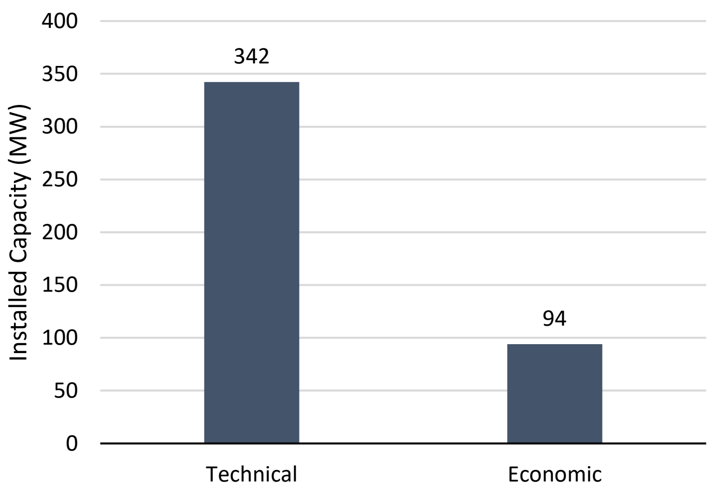
[58] The Bass Diffusion Curve (also referred to as the Bass Model or Bass Diffusion Model) is a simple differential equation that models the adoption of technology over time in a given population.
[59] For a full description of National Grid's current incentives for CHP, please see: https://www.nationalgridus.com/RI-Business/Energy-Saving-Programs/Cogeneration

For these reasons, smaller and micro-CHP systems are more likely to receive smaller incentive amounts (as a proportion of project capital costs) due to higher per-kW installed costs and typically lower efficiencies due to factors such as serving more variable thermal loads. Under all scenarios in this study, modeled CHP systems have efficiencies greater than 55% as required by National Grid's current CHP program and therefore would be eligible for incentive payments. However, the study does not explicitly model incentive payments that may be below the maximum allowable amount of 70% of capital costs.

4.2 Technical and Economic Potential

The study estimates there is approximately 342 MW of technical potential in terms of installed capacity in Rhode Island, which would produce approximately 953 GWh of electricity annually and reduce peak demand by 127 MW. This capacity is distributed across 720 individual units with an average size of 460kW. This result represents the amount of CHP that might be expected if all eligible customer thermal load was supplied by CHP systems regardless of customer economics.

Figure 4-2. Technical and Economic CHP Potential (Installed Capacity)



When CHP systems are sized with customer payback in mind, only 94MW of installed capacity is considered economic representing approximately 27% of technical potential as shown in Figure 4-2. This capacity is distributed across 144 individual units with an average size of 630kW. Compared to technical CHP potential, the average size of economic CHP systems is larger because smaller systems tend to be less economic from the customer's perspective due to higher system and interconnection costs on a per unit of capacity basis.

While the analysis considers CHP systems with a minimum size threshold of 20kW, which could enable buildings with lower thermal loads that are not traditionally CHP candidates (e.g. office and retail buildings) to become viable opportunities for CHP as these systems can be applied in situations with lower thermal loads. The results, however, suggest that small and micro-CHP systems are not a significant contributor to CHP potential in Rhode Island over the study period. Of the 94MW of economic potential, less than 6% is attributable to systems less than 100kW and only two systems were sized between 20kW and 24kW.

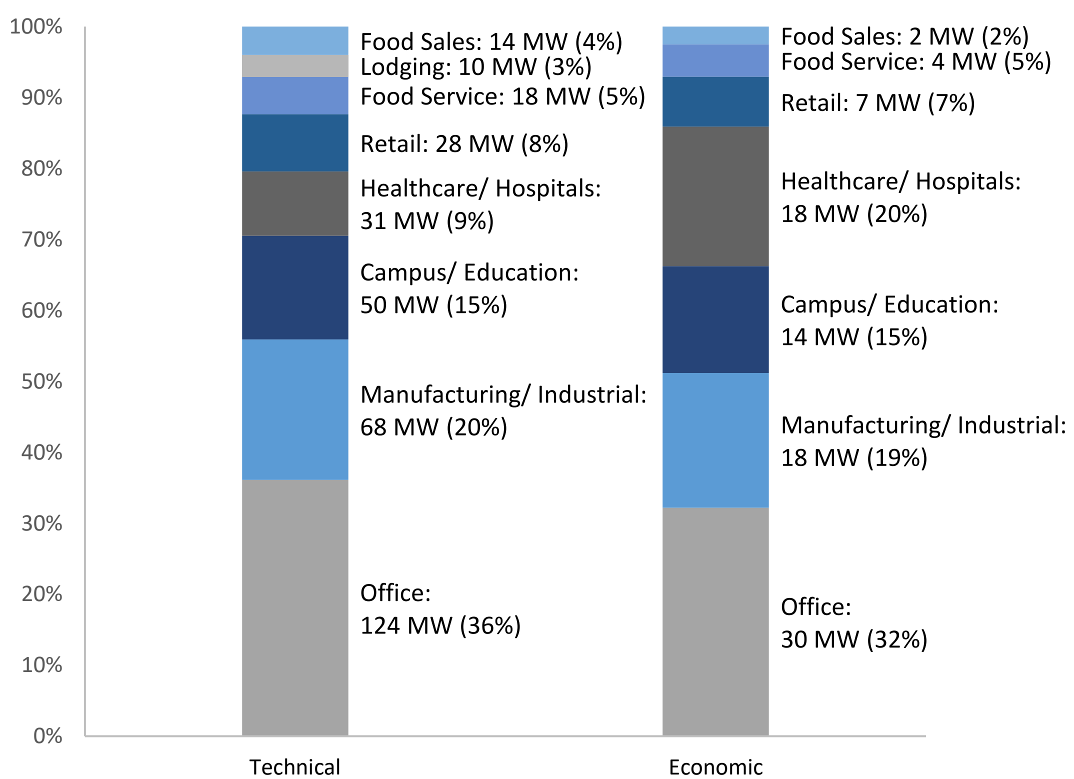
Economic CHP capacity would produce approximately 398 GWh annual and provide 35 MW of peak demand reduction. Table 4-1 summarizes the key metrics for technical and economic potential.

Table 4-1. Technical and Economic Potential Summary Table

	Technical	Economic
Annual Electricity Production (GWh)	953	398
Peak Demand Reduction (MW)	127	35
Annual Natural Gas Consumption (Thousand MMBtu)	-5,609	-2,354
Number of units	720	144
Average unit size (MW)	0.46	0.63

At the segment level, the largest amount of CHP potential is found in the office segment with significant amounts of potential in the manufacturing & industrial, campus & education, and healthcare & hospitals segments as shown in Figure 4-3.

Figure 4-3. Proportion of Technical and Economic CHP Potential by Segment



As can be seen in Table 4-2, the study estimates there is zero technical potential for CHP in the warehouse and other commercial segments. There is limited technical potential in the lodging segment, but no economic potential.

Table 4-2. Number of Units and Average Unit Size by Segment (Technical and Economic Potential)

Segment	Technical Potential		Economic Potential	
	Number of Units	Average Unit Size (MW)	Number of Units	Average Unit Size (MW)
Office	269	0.45	45	0.65
Retail	66	0.40	14	0.45
Food Service	58	0.30	11	0.39
Healthcare & Hospitals	61	0.49	23	0.77
Campus & Education	105	0.46	22	0.63
Warehouse	0	0.00	0	0.00
Lodging	22	0.46	0	0.00
Other Commercial	0	0.00	0	0.00
Food Sales	30	0.45	5	0.42
Manufacturing & Industrial	108	0.60	23	0.74

While CHP potential in segments such as manufacturing & industrial, campus & education, and healthcare & hospitals is expected due to the concentration of existing systems and typically larger customer thermal loads amenable to CHP applications in these segments, the large proportion of CHP potential in office buildings is a somewhat surprising result of this analysis. This result may be attributable to uncertainty in customer segment assignments. Estimating CHP potential at the segment level requires accurate customer segmentation data. The data used for this analysis, however, had significant gaps in customer segmentation information with many accounts that could not be accurately assigned to a specific segment. A large amount of estimated potential is attributable to these "unknown" accounts. The analysis assigns this potential to each segment on a pro-rated basis based on the amount of CHP potential attributable to "known" accounts. Table 4-3 shows estimated economic potential by segment prior to distribution unknown CHP potential.

Table 4-3. Number of Units and Average Unit Size by Segment Prior to Distribution of Unknown Accounts (Economic Potential)

Segment	Economic Potential	
	Number of Units	Average Unit Size (MW)
Office	25	0.75
Retail	8	0.38
Food Service	6	0.26
Healthcare & Hospitals	13	0.98
Campus & Education	12	0.71
Warehouse	0	0.00
Lodging	0	0.00
Other Commercial	0	0.00
Food Sales	3	0.31
Manufacturing & Industrial	13	0.93
Unknown	*64*	*0.53*

This approach for distributing unknown CHP potential may be over-weighting the office segment (e.g. if there are few “unknown” office accounts) and thereby skewing results. Additional market research is required to verify these segment level results.

4.3 Achievable Potential

Under the Low and Mid scenarios, which limit incentive payments to 70% of capital costs, the study estimates that CHP programs could incentivize 3.5 MW (Low) to 4.5 MW (Mid) of additional installed capacity per year during the study period resulting in an cumulative 20.8 MW to 27.3 MW of additional CHP capacity by 2026. Under the Max scenario, CHP adoption significantly increases to approximately 11.1 MW of capacity per year.

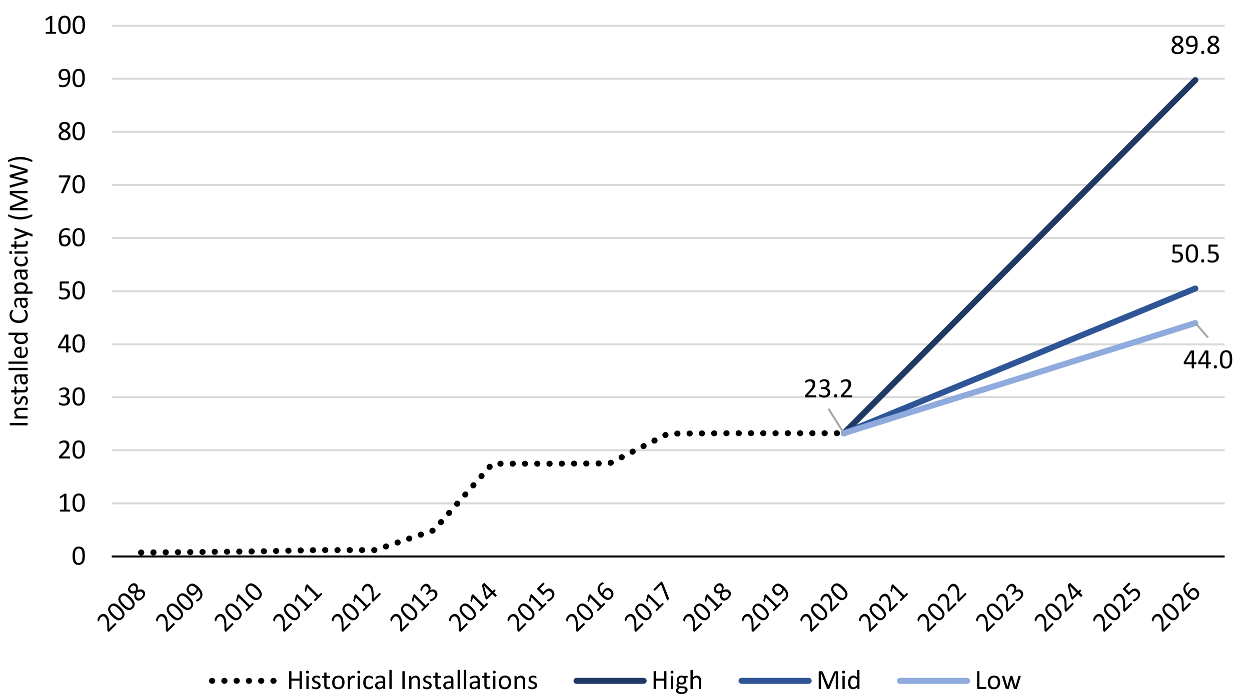
Table 4-4 presents the expected electric energy and peak demand savings, gas consumption increases, and annual program costs under each scenario associated with these capacity additions. The large increase in annual capacity additions under the Max scenario relative to the Low and Mid scenarios suggests that customer economics is a limiting factor for CHP adoption in Rhode Island, while the relatively smaller difference between the Mid and Low scenarios suggests that reducing market barriers will have a limited – although not negligible – impact on adoption.

Table 4-4. Achievable CHP Potential Summary Table (2021-2026 Averages; All Scenarios)

Impact	Max	Mid	Low
Annual Capacity Additions (MW)	11.1	4.5	3.5
Incremental Annual Electric Savings (MWh)	45,209	18,526	14,106
Incremental Lifetime Electric Savings (MWh)	723,337	296,409	225,700
Incremental Annual Demand Reductions (MW)	4.12	1.69	1.28
Annual Gas Consumption Increase (MMBtu)	266,891	109,366	83,277
Annual Program Costs (Million $2021)	$29.6M	$9.0M	$6.7M

Figure 4-4 shows historical and projected adoption of CHP in Rhode Island under each scenario. Adoption under the Low Scenario is similar to historical adoption of an average of 3.6MW per year since 2014 when National Grid began offering CHP incentives. Adoption under the Mid – and particularly – Max scenarios represent a significant increase in the rate of CHP adoption compared to past years.

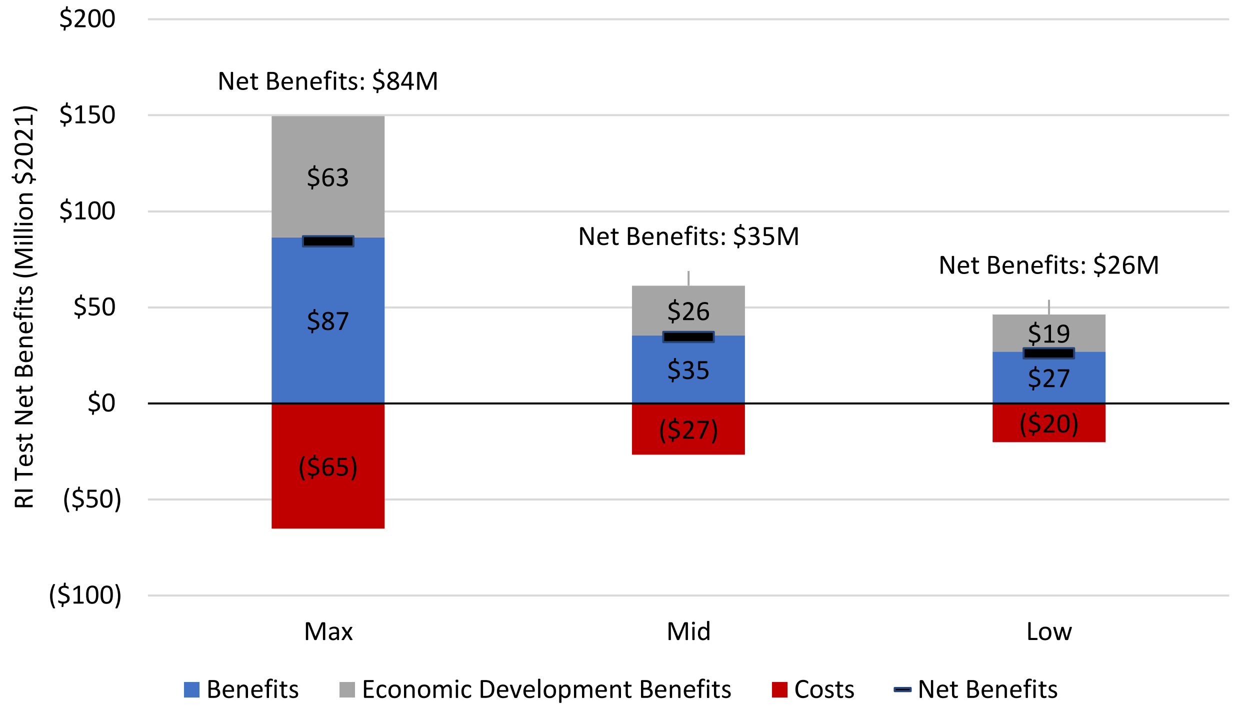
Figure 4-4. Historical and Projected CHP Capacity in Rhode Island (All Scenarios)



Note: Historical installations are based on interconnection data provided by National Grid.

Based on the RI Test, the average annual net benefits generated each year range from $26 million (Low) to $84 million (Max) as shown in Figure 4-5. These benefits account for the increase in natural gas consumption that will occur and include an average annual addition of $19 million (Low) to $63 million to Rhode Island's state gross domestic product each year resulting from "the effects of program and participant spending that creates jobs in construction and other industries as the project is planned, and equipment is purchased and installed". [60] Even without considering state-level economic benefits, CHP delivers net benefits to rate payers through avoiding costs associated with generating electricity; building electricity generation, transmission and distribution capacity; reducing emissions; and other benefits.

Figure 4-5. 2021-26 Average Annual RI Test Net Benefits Generated Each Year (All Scenarios)



4.3.1 Net Energy Savings

A key benefit of CHP is the efficiency gains resulting from simultaneously producing useful thermal and electricity onsite, which can achieve efficiencies greater than 80%, while using electricity from the grid and producing on-site thermal energy only typically has an efficiency in the range of 45-55%. This difference in efficiency is primarily driven by the generation of grid electricity, which generally does not capture the waste heat produced in the process.

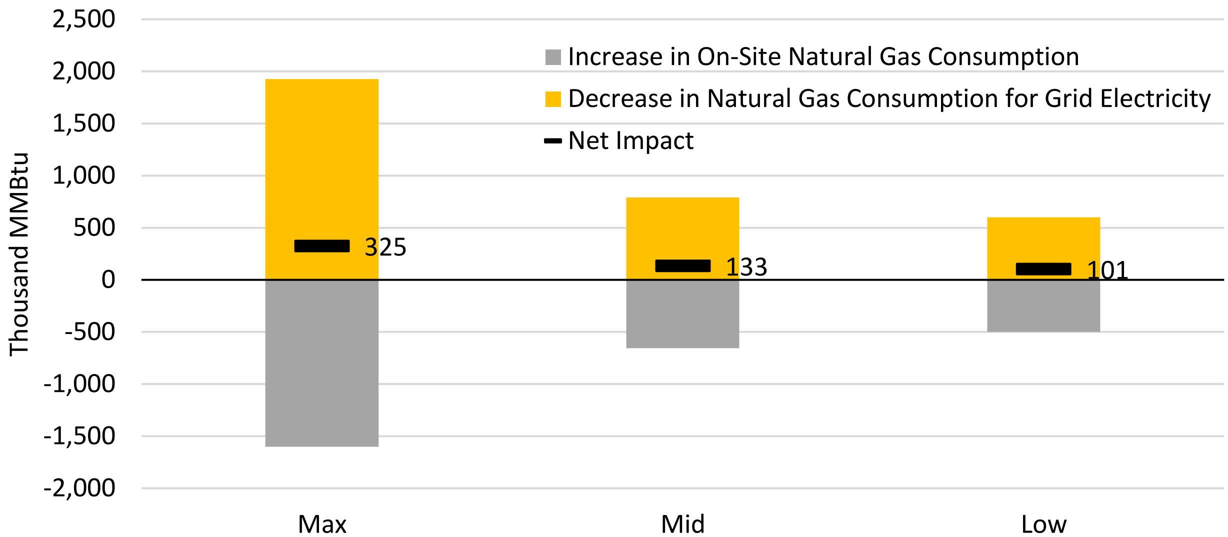
When these efficiency gains are considered, CHP adoption in Rhode Island will result in net reductions in energy consumption and greenhouse gas emissions. By 2026, CHP adoption could reduce net energy consumption by an equivalent of 101 thousand MMBtu (Low) to 325 thousand MMBtu (Max) per year as

[60] For a full description of the benefits included in the RI Test, please see the Attachment 4 - 2020 Rhode Island Test Description as filed with National Grid's 2020 EEPP (Docket No. 4979) accessible at: http://www.ripuc.ri.gov/eventsactions/docket/4979-NGrid-EEPP2020%20(10-15-19).pdf

shown in Figure 4-6[61] This is equivalent to approximately 22% to 77% of natural gas incremental annual savings achieved by National Grid in 2019 (approximately 451 thousand MMBtu).[62]

This net reduction in energy consumption will result in an annual reduction in emissions of approximately 11 to 34 thousand tons of CO_2, which is equivalent to removing 2,400 to 7,300 passenger vehicles from the road for a year.[63]

Figure 4-6. Annual Net Energy Savings by 2026 (All Scenarios)

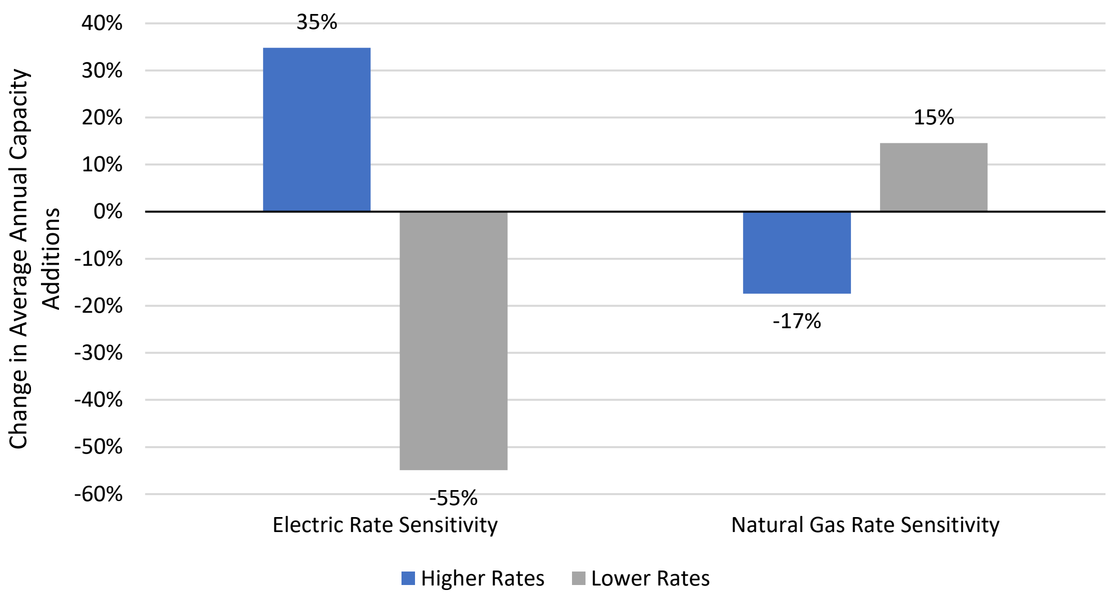


4.4 Sensitivity Analysis

CHP adoption is tested against two sensitivities – retail electricity rates and retail natural gas rates. Ultimately, higher electricity rates and lower natural gas rates will drive greater adoption of CHP as the economics of CHP systems improve, while lower electricity rates and higher natural gas rates drive the opposite reaction. As can be seen in Figure 4-7, fluctuations in electricity rates have a much larger proportional impact on adoption relative to fluctuation in natural gas rates – impacting average annual capacity additions by between 35 and 55% compared to 15 and 17%, respectively.

[61] The net energy savings analysis assumes that electricity generated by CHP displaces electricity generated by natural gas power plants with a heat rate of 7,100 Btu/kWh as estimated in the *Avoided Energy Supply Components (AESC) in New England: 2018* report.
[62] National Grid 2019 savings based on draft 2019 results included in of the 2019 Energy Efficiency Fourth Quarter Report provided in March 2020.
[63] Passenger vehicle estimate calculated using the EPA Greenhouse Gas Equivalencies Calculator accessible at: https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator

Figure 4-7. Proportional Impact of Electric and Natural Gas Rate Sensitivity on 2021-26 Average Annual Installed CHP Capacity Additions (Mid Scenario)



In terms of absolute impacts, higher electricity rates will increase average annual capacity additions under the Mid scenario from 4.5MW to 6.1MW, while lower electricity rates will decrease it to 2.1MW. Higher natural gas rates will decrease capacity additions from 4.5MW to 3.8MW, while lower rates will increase annual capacity additions to 5.2MW.

4.5 Key Takeaways

Based on the results presented in this chapter, the following key takeaways emerge:

Additional CHP potential exists, and current incentive levels can encourage adoption over the study period that is commensurate with recent years. Customer natural gas consumption in Rhode Island suggests there is a continued opportunity to supply thermal demands with CHP.

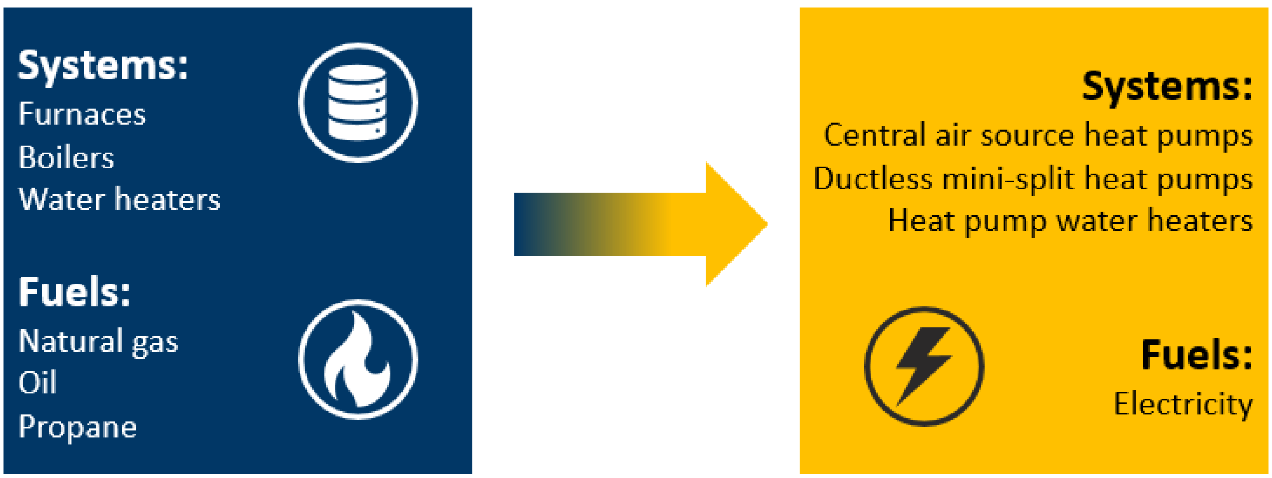
The biggest opportunities are in the Office, Healthcare & Hospitals, Education & Campus, and Manufacturing & Industrial segments. Relatively larger opportunities in the latter segments is not surprising based on typical CHP applications, but the significant potential in the Office segment represents a potential new opportunity for CHP deployment in Rhode Island. However, due to limitations in accurately segmenting customer data, further market research should be conducted to validate these findings.

Reducing non-financial barriers through enabling activities may move the market a little, but overall impact is small compared to increasing customer payback (e.g. increased incentives). The up-front capital costs of CHP are often a significant hinderance to CHP adoption.

5 Heating Electrification

5.1 Overview

The following chapter presents results for the heating electrification (HE) module of the market potential study (MPS). The HE module estimates the potential for replacing or retrofitting existing heating systems with air source heat pumps (ASHPs) and ductless mini-split heat pumps (DMSHPs) to displace heating from fossil-fuel based (natural gas, oil, and propane) space and water heating systems over the study period.[64]



The chapter first briefly summarizes key results, the approach used to estimate HE potential, and the program scenarios explored in the analysis. A full description of the methodology can be found in Appendix B. Results are then presented in the following order:

- **Program savings**. Savings are presented in terms of *incremental lifetime fuel savings* achieved during the study period. Program savings do not incorporate impacts on electricity consumption anticipated from heating electrification, which are covered under system impacts as described below.
- **Portfolio metrics**. The benefits and costs of efficiency savings are presented at the portfolio-level.
- **Sensitivity analysis**. The impact of various sensitivities scenarios on program savings and portfolio metrics are presented.
- **System impacts**. Savings are presented in terms of *cumulative* savings to provide an assessment of system-level impacts of heating electrification savings. System impacts include both the

[64] To avoid double-counting, new construction heating electrification is not considered in this model as it is implicitly captured in new construction measures within the EE measures.

reduction in fuel consumption and increase in electricity consumption anticipated from heating electrification.

5.1.1 Summary of Results

Overall, the study estimates that heating electrification programs can procure an average of 658 thousand MMBtu (Low) to 10,453 thousand MMBtu (Max) of incremental lifetime fuel (natural gas, oil, and propane) savings each year during the study period with most of these savings coming from displacing delivered fuel space and water heating. The bulk of savings are in the residential and residential low-income sectors across all scenarios with most savings coming from the residential low-income sector in the Low scenario and savings shifting to the residential sector as incentives are increased in the Mid and Max scenarios.

In terms of electric impacts, heating electrification could increase electricity consumption by 17 GWh (Low) to 284 GWh (Max) by 2026, which would increase forecasted electricity sales by 0.2% to 3.7%, respectively. These impacts are net of savings that will occur from the provision of more efficient space cooling from the installation of heat pumps for space heating.

However, while heating electrification will increase electricity consumption, it will also result in a reduction in overall electric peak demand in Rhode Island as the study assumes the majority of heat pumps adopted for space heating electrification will also provide more efficient space cooling for most customers and Rhode Island is a summer peaking system. By 2026, heating electrification could decrease peak demand by 0.7 MW (Low) to 12.8 MW (Max) resulting in an overall reduction in peak demand of 0.04% to 0.7%, respectively.[65]

5.1.2 Approach

The market potential for heating electrification is estimated using the DEEP model as described in Appendix A. Methodological aspects unique to the HE module can be found in Appendix B. The module defines representative use cases that characterize the most common heating electrification opportunities for each sector within the study period. Each use case consists of an existing fossil-fuel space or water heating system that is being displaced by a heat pump system. For space heating, the heat pump systems are segmented into either central ASHPs or DMSHPs. Ground source heat pumps are not included in this analysis due to the high cost of retrofitting these systems in the existing building stock. Air-to-water heat pumps are also excluded from this analysis, due to their prohibitive costs which renders them largely commercially unviable over the study period.

In addition to estimating the potential for fuel savings (natural gas, oil, and propane), the module also estimates the commensurate impact on electricity consumption and peak demand that will occur with heating electrification. The study considers both the *increase* in electricity consumption that will occur from using electric heat pumps to provide space and water heating as well as any *decreases* that may occur from the provision of more efficient space cooling from heat pumps adopted for heating purposes.

[65] Peak demand reductions only occur for customers with existing lower efficiency air conditioners, or customers who are likely to adopt air conditioning during the study period. For customers without existing AC and that are unlikely to have naturally adopted AC during the study period, heating electrification results in an increase in peak demand. In Rhode Island, most customers have existing AC, thus resulting in overall peak demand reductions from heating electrification.

Since Rhode Island is a summer peaking jurisdiction, the study estimates the impact of on peak demand resulting from the air cooling from heat pumps adopted for heating purposes.

5.1.3 Program Scenarios

The HE module explores three program scenarios as described in Figure 5-1.

Figure 5-1. HE Program Scenario Descriptions

Low	Applies 25% incentives and enabling activities in line with National Grid's proposed 2020 Energy Efficiency Program Plan, except for the residential low-income sector, which continues to receive a 100% incentive.
Mid	Applies 50% incentives and additional enabling strategies, except for the residential low-income sector, which continues to receive a 100% incentive.
Max	Incentives set at 100% to completely eliminate customer costs and applies same enabling strategies as under Mid scenario.

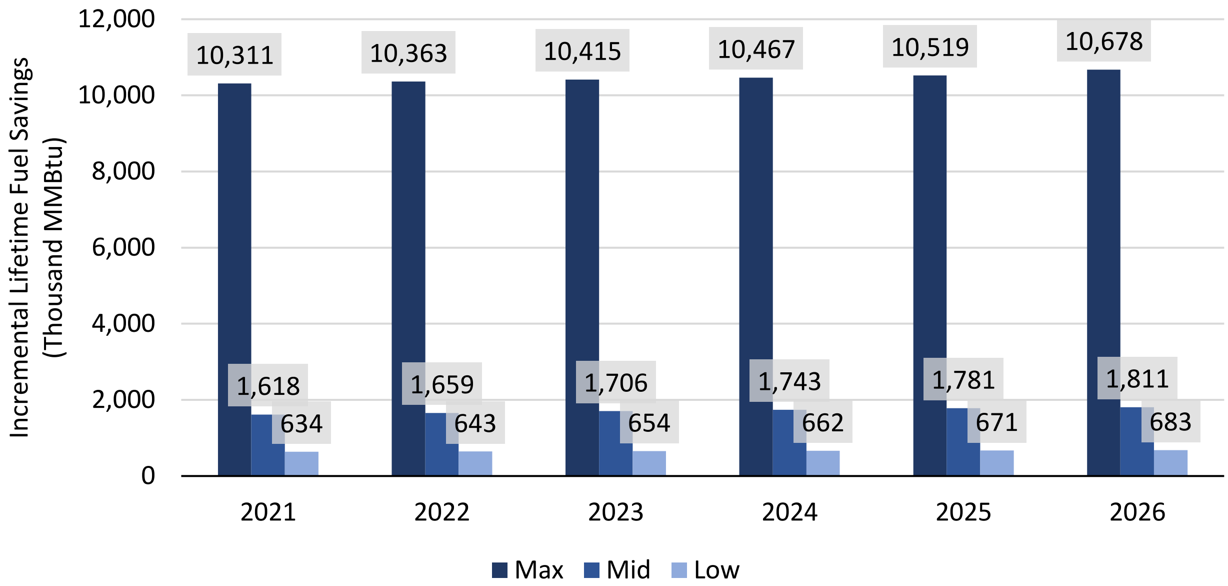
While the study explores varying incentive levels, it does not explicitly model the impact of possible financing options made available for heating electrification measures such as the Rhode Island HEAT Loan Program, which offers loans for eligible particpants at 0% interest to pay for efficient heating systems.[66] The additional customer incenitve offered via the 0% HEAT loans would be accounted for under the elevated incentive levels in the Mid and Max scenarios.

5.2 Program Savings

The study estimates that heating electrification programs can procure an average of 658 thousand MMBtu (Low) to 10,453 thousand MMBtu (Max) of incremental lifetime fuel (natural gas, oil, and propane) savings each year during the study period as shown in Figure 5-2.[67] Savings under the Max scenario are much larger than under the Low and Mid scenarios. While average incremental lifetime savings are approximately 160% higher under the Mid scenario relative to the Low scenario, savings under the Max scenario are nearly 1,500% higher than the Low scenario. This result suggests that achievable potential for heating electrification is highly constrained by customer economics.

[66] For more information on the Rhode Island HEAT Loan, please see the *Heat Loan Assessment* report accessible at: http://rieermc.ri.gov/wp-content/uploads/2019/05/heat-loan-assessment-final-report_111918.pdf
[67] Please note that program savings as presented here do not account for the increase in electricity consumption that will occur with heating electrification, which is presented later in this chapter.

Figure 5-2. Incremental Lifetime Fuel Savings by Year (All Fuels; 2021-26; All Scenarios)



Note: Program savings only represent natural gas and delivered fuel savings and do not include net increases in electricity consumption resulting from heating electrification.

As shown in Table 5-1, the vast majority of program savings come from delivered fuel measures and relatively little come from natural gas measures. This is due to most natural gas electrification potential failing to pass economic screening under the RI Test.[68] Under the Mid scenario, 82% of all savings result from electrifying existing delivered fuel space and water heating systems.

Table 5-1. HE Incremental Lifetime Savings for All Fuels, Delivered Fuels, and Natural Gas by Year (All Scenarios)

Program Savings	Scenario	2021	2022	2023	2024	2025	2026	Average
Natural Gas Incremental Lifetime Savings	Max	853	857	861	866	870	883	**865**
	Mid	311	306	310	314	319	320	**313**
	Low	34	34	35	36	37	37	**35**
Delivered Fuel Incremental Lifetime Savings	Max	9,458	9,506	9,553	9,601	9,649	9,795	**9,594**
	Mid	1,307	1,353	1,396	1,428	1,461	1,491	**1,406**
	Low	600	610	619	626	634	646	**622**
All Fuel Incremental Lifetime Savings	*Max*	*10,311*	*10,363*	*10,415*	*10,467*	*10,519*	*10,678*	***10,459***
	Mid	*1,618*	*1,659*	*1,706*	*1,743*	*1,781*	*1,811*	***1,720***
	Low	*634*	*643*	*654*	*662*	*671*	*683*	***658***

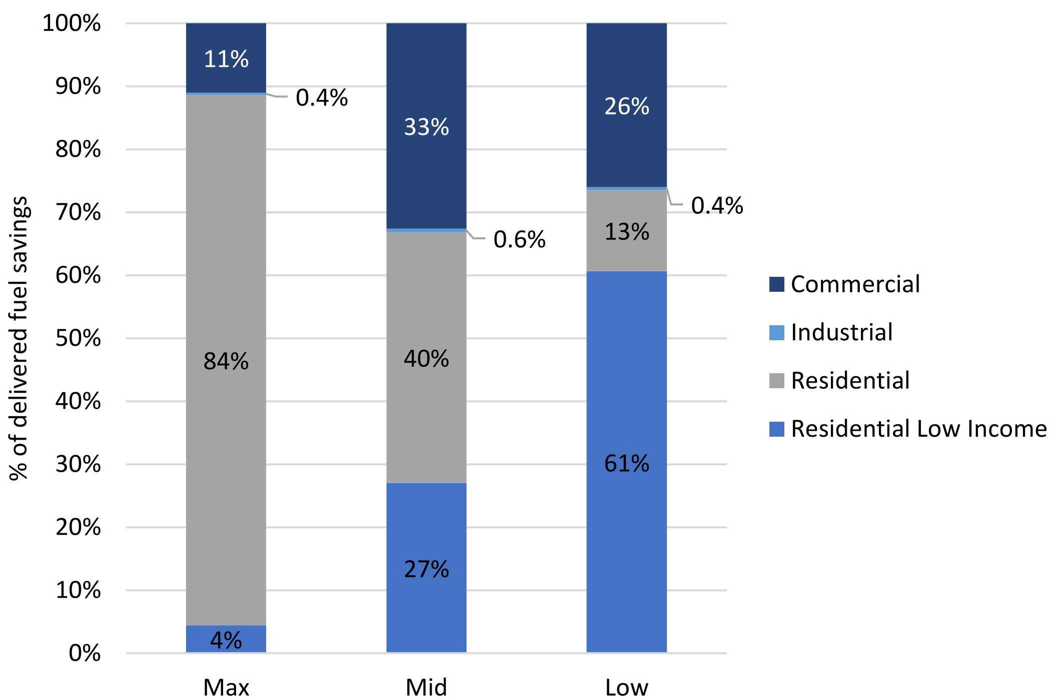
Note: Program savings only represent natural gas and delivered fuel savings and do not include net increases in electricity consumption resulting from heating electrification.
Units: Thousand MMBtu

[68] Heating electrification measures were screened for cost-effectiveness based on the Rhode Island Benefit Cost Test ("RI Test") as approved by the Rhode Island Public Utility Commission in Docket 4755 and in accordance with the Docket 4600 Benefit-Cost Framework.

5.2.1 Program Savings by Market Sector

The bulk of heating electrification fuel savings come from the residential and residential low-income sectors across all scenarios as shown in Figure 5-3. Under the Low scenario, 61% of savings come from the residential low-income sector, which is driven by the assumption that this sector receives a 100% incentive. Limited adoption then occurs in the remaining sectors that receive a 25% incentive. However, as incentives increase for the other sectors in the Mid and Max scenarios, the relative proportion of fuel savings from the residential low-income shrink. Under the Max scenario, most savings come from the residential sector.

Figure 5-3. Proportion of HE Savings by Sector (Average Incremental Lifetime Fuel Savings)



As shown in Table 5-2, the average incremental lifetime fuel savings over the study period in the commercial and industrial (C&I) market are significantly less than the residential sector. This reflects the larger size of commercially viable heating electrification options in the residential sector.

Table 5-2. HE Savings by Sector (All Fuels; 2021-2026 Average Incremental Lifetime Savings; All Scenarios)

Sector	Max	Mid	Low
Residential Low Income	465	465	399
Residential	8,801	684	85
Industrial	39	10	3
Commercial	1,153	560	171
Total	*10,459*	*1,720*	*658*

Note: Program savings only represent natural gas and delivered fuel savings and do not include net increases in electricity consumption resulting from heating electrification.
Units: Thousand MMBtu

Block Island and Pascoag Utility District

Heating electrification fuel savings for the Block Island Utility District ("Block Island") and Pascoag Utility District (PUD) are estimated by scaling estimated savings for National Grid based on each utility's relative residential and C&I customer count. A full description of this scaling process is provided in Appendix F.

As shown in Table 5-3 and Table 5-4, the study estimates there is an additional 10.1 (Low) to 135.2 (Max) Thousand MMBtu of incremental lifetime fuel savings per year in the Block Island and PUD jurisdictions. PUD has greater potential due to a greater number of residential customers relative to Block Island. Both utilities have similar amounts of commercial and industrial potential due to similar numbers of these customers in their territories. Overall, the combined estimated savings potential for PUD and Block Island is between 1.3% (Max) and 1.5% (Low) of heating electrification fuel savings estimated for National Grid's customer base.

Table 5-3. HE Fuel Savings by Sector for Block Island Utility District (2021-2026 Average Incremental Lifetime Savings; All Scenarios)

Sector	Max	Mid	Low
Residential Low Income	0.16	0.16	0.13
Residential	2.95	0.23	0.03
Industrial	0.53	0.13	0.04
Commercial	15.58	7.57	2.31
Total	*19.2*	*8.1*	*2.5*

Note: Program savings only represent natural gas and delivered fuel savings and do not include net increases in electricity consumption resulting from heating electrification.
Units: Thousand MMBtu

Table 5-4. HE Fuel Savings by Sector for Pascoag Utility District (2021-2026 Average Incremental Lifetime Savings; All Scenarios)

Sector	Max	Mid	Low
Residential Low Income	4.98	4.98	4.27
Residential	94.17	7.32	0.91
Industrial	0.56	0.14	0.04
Commercial	16.30	7.92	2.42
Total	*116.0*	*20.4*	*7.6*

Note: Program savings only represent natural gas and delivered fuel savings and do not include net increases in electricity consumption resulting from heating electrification.
Units: Thousand MMBtu

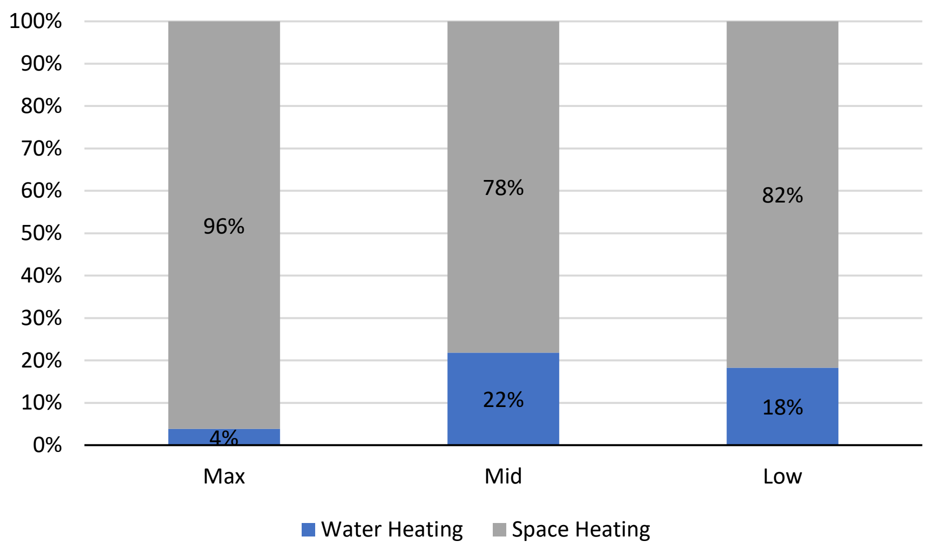
5.2.2 Residential Program Savings by End Use

In the residential sector, electrifying space heating systems provides the majority of savings under all scenarios. This can be attributed to two factors. First, and most importantly, households consume more energy for space heating than water heating, therefore creating a bigger opportunity in terms of MMBtu saved for electrifying space heating. Second, heat pump water heaters face significant constraints to their installation in existing homes. As explained in more detail in Appendix B, this study assumes only 36% of homes in Rhode Island can feasibly host a heat pump water heater based on the results of recent Heat

Pump Water Heater Feasibility Assessment conducted for Rhode Island.[69] The study found that most homes have water heaters installed in spaces that are not amenable to heat pump water heaters (e.g. not tall or large enough, year-round temperatures below 50F, etc.).

In the Max scenario the proportion of savings from water heating shrinks to just 4%, largely because the potential from space heating electrification measures grows significantly when 100% of the incremental costs are covered by incentives, as shown in Figure 5-4 below. This implies that water heating electrification is more cost effective for consumers relative to space heating electrification in the Mid and Low scenarios where incentives are lower. The savings from electrifying water heating systems increases between the Low and Mid scenarios as savings from these measures increase at a faster rate relative to space heating measures (see Table 5-5).

Figure 5-4. Proportion of Residential HE Fuel Savings by End-use (2021-26 Average; All Scenarios)



As savings ramp up considerably under the Max scenario, the vast majority of savings come from electrifying space heating as savings from this end use increase at a much faster rate relative to water heating measures. Between the Mid and Max scenarios, fuel savings from electrifying space heating increase by nearly ten-fold.

Table 5-5. Residential HE Savings by End Use (All Fuels; 2021-2026 Average Incremental Lifetime Savings; All Scenarios)

End Use	Max	Mid	Low
Water Heating	355	251	95
Space Heating	8,911	898	405

Note: Program savings only represent natural gas and delivered fuel savings and do not include net increases in electricity consumption resulting from heating electrification.
Units: Thousand MMBtu

[69] The Heat Pump Water Heater Feasibility Assessment is a component of the National Grid Rhode Island Residential Appliance Saturation Survey (Study RI2311).

These results suggest that relatively smaller increases in incentives for water heating electrification can have a bigger impact on shifting customer behavior, while much larger incentives are needed to move the market for electrifying space heating.

In terms of number of customers that may be impacted by HE programs, Figure 5-5 and Figure 5-6 show the estimated number of residential customers that adopt heat pumps for space and water heating, respectively, under the Mid scenario. Roughly 900 to 1,100 customers would adopt heat pumps for space heating under the Mid scenario each year, while roughly 1,600 to 1,700 customers would adopt heat pump hot water heaters.

Figure 5-5. Number of Residential Customers Adopting Heat Pumps per Year for Space Heating (2021-26; Mid Scenario)

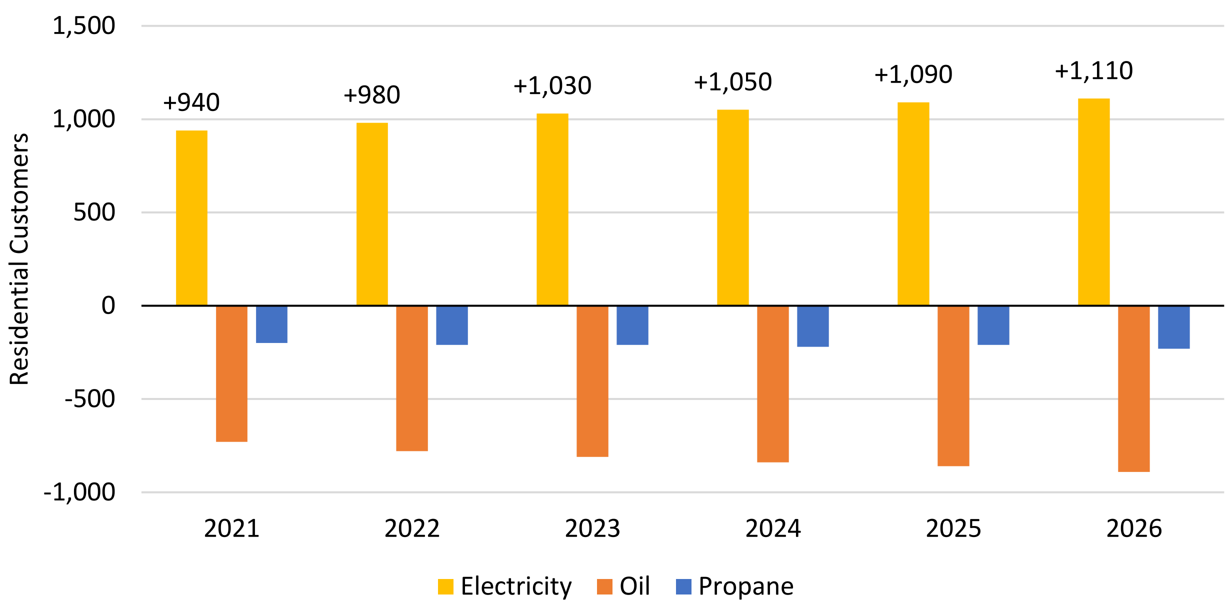
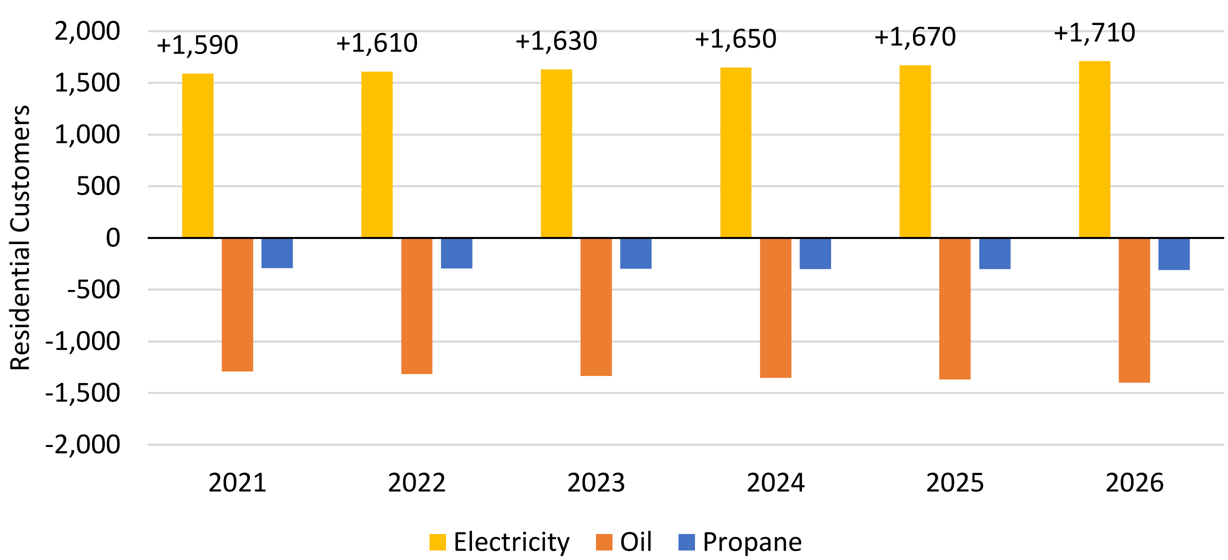


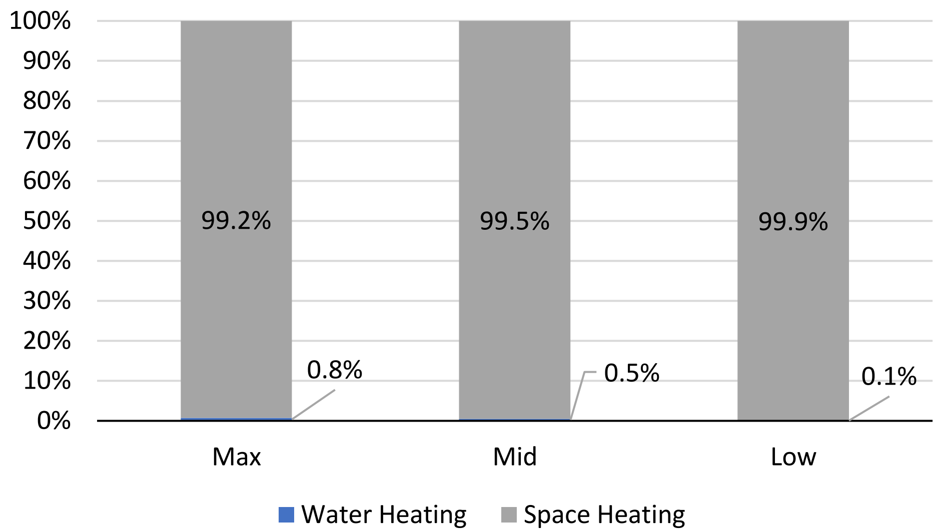
Figure 5-6. Number of Residential Customers Adopting Heat Pumps per Year for Water Heating (2021-26; Mid Scenario)



5.2.3 C&I Program Savings by End Use

Almost all C&I fuel savings from HE come from electrifying space heating. Space heating measures represent greater than 99% of fuel savings under all scenarios as shown in Figure 5-7.

Figure 5-7. Proportion of C&I HE Fuel Savings by End-use (2021-26 Average; All Scenarios)



Unlike the residential sector, some of the fuel savings for the C&I sectors include natural gas. Under the Mid scenario, approximately 55% of fuel savings are natural gas with the remaining 45% from delivered fuels. Natural gas fuel savings pass economic screening in the C&I sectors due to the significant cooling benefits provided by heat pumps installed in C&I buildings. C&I buildings typically have higher cooling loads than residential homes, so greater cooling-related energy savings can be gained through the installation of a heat pump. These additional savings help make these systems more cost-effective.

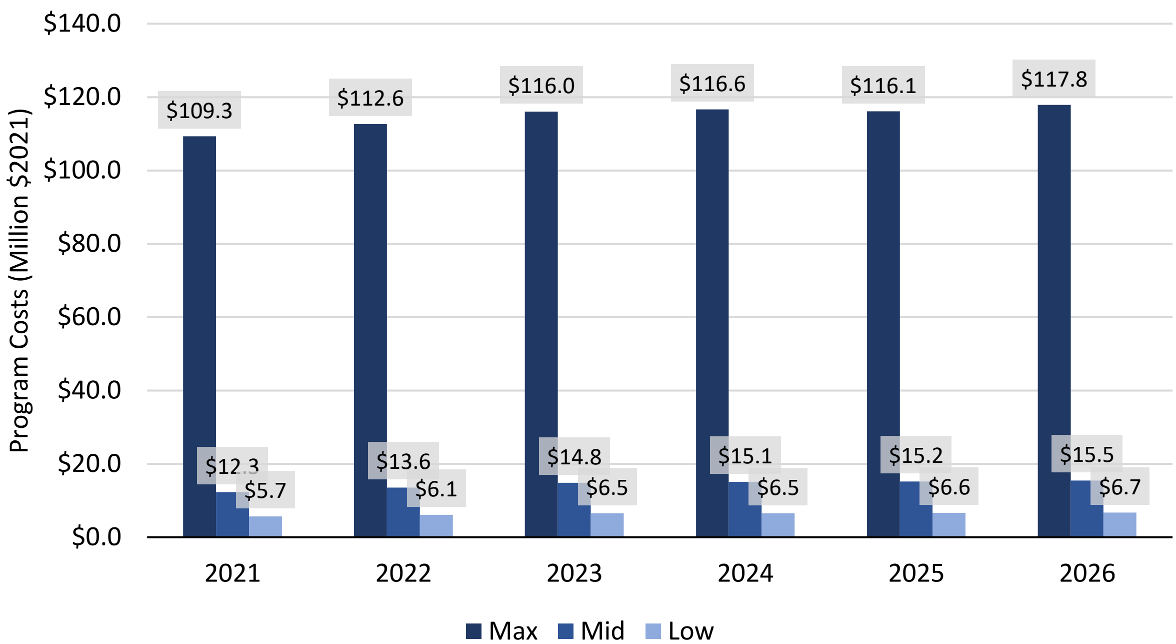
5.3 Portfolio Metrics

5.3.1 Program Costs

The study estimates that HE program costs will range between an average of $6.3 to $14.4 million under the Low and Mid scenarios, respectively, slowly increasing year-over-year as shown in Figure 5-8. Under the Max scenario, estimated costs will average $115 million per year. This significant jump in estimated costs coincides with the large increase in heat pump adoption observed between the Mid and Max scenarios as previously discussed.

Under the Low scenario, the bulk of program costs (87%) are attributable to the residential low-income sector with average costs estimated at approximately $5.5 million per year. As fuel savings increase in other sectors under the Mid and Max scenarios, programs costs shift as well. Under the Max scenario, approximately 87% of program costs are associated with the non-low-income residential sector. Additional detail on estimated program costs can be found in Appendix G.

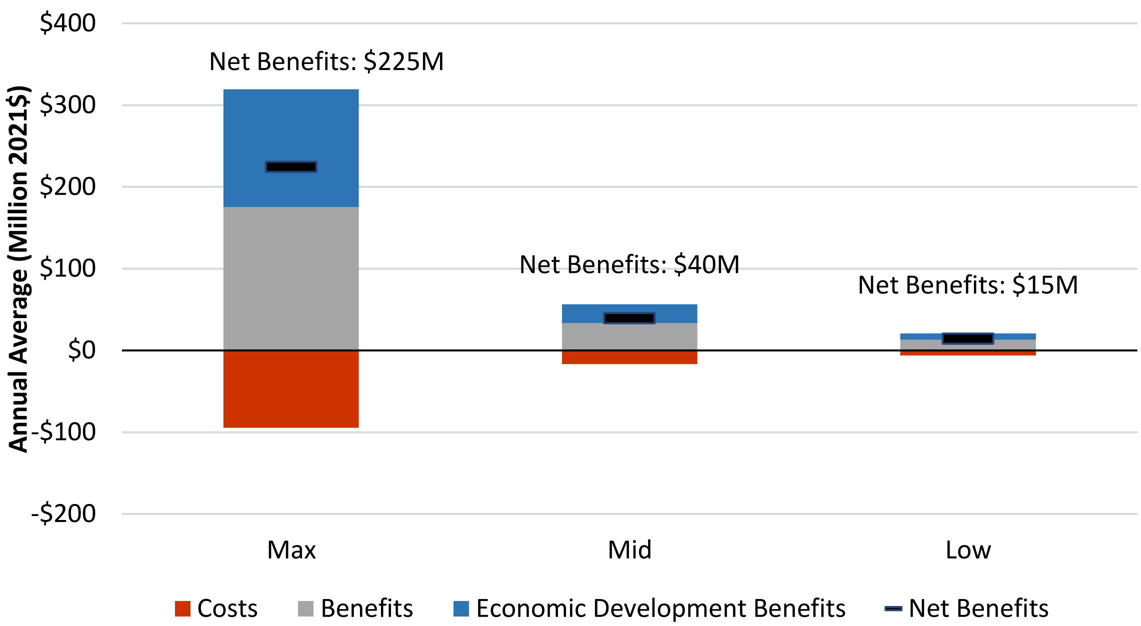
Figure 5-8. HE Program Costs by Year (2021-26; All Scenarios)



5.3.2 Program Benefits

In all scenarios, electrification creates significant benefits to rate payers, customers, and society at large. Based on the RI Test, average net benefits generated each year range from $15 to $40 million under the Low and Mid scenarios, respectively, as shown in Figure 5-9. Under the Max scenario, $225 million in net benefits are generated each year on average. These benefits include an average annual addition of $8 million (Low) to $23 million (Mid) to Rhode Island's state gross domestic product (GDP) each year. Even without the addition of state-level economic benefits, heating electrification measures create significant rate payer benefits through avoiding costs associated with natural gas and delivered fuel delivery even when the additional costs of supplying electricity are considered.

Figure 5-9. Average Annual RI Test Net Benefits Generated Each Year (All Scenarios)



HE will also result in significant customer benefits and GHG reductions. As shown in Figure 5-10 and Figure 5-11, average lifetime customer bill savings (e.g. reduction in gas or delivered fuel costs net of electricity cost increases) generated each year range from $6.7 million to $12.7 million under the Low and Mid scenarios, respectively, while GHG emission reductions range from 2,000 to 4,000 short tons of carbon-dioxide equivalent (tCO_2e) each year.[70, 71] This is roughly equivalent to removing 390 to 780 passenger vehicles from the road for a year.[72] Under the Max scenario, lifetime customer bill savings generated each year approach $60 million and GHG emission reductions generated each year are 23,000 short tons or approximately 4,500 passenger vehicles.

[70] Lifetime customer net bill savings are calculated by summing the annual bill savings over the effective lifetime of the measure and subtracting the portion of the measure's incremental cost paid by the customer (e.g. the customer pays 70% of the incremental cost when the utility offers a 30% incentive).
[71] Emission reductions are estimated using emission factors from the *Avoided Energy Supply Components (AESC) in New England: 2018* report. See Appendix F for more details.
[72] Passenger vehicle estimate calculated using the EPA Greenhouse Gas Equivalencies Calculator accessible at: https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator

Figure 5-10. Average Lifetime Customer Net Benefits Generated Each Year (2021-26; All Scenarios)

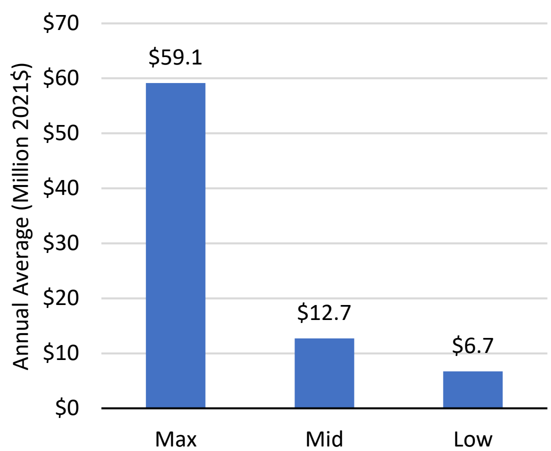
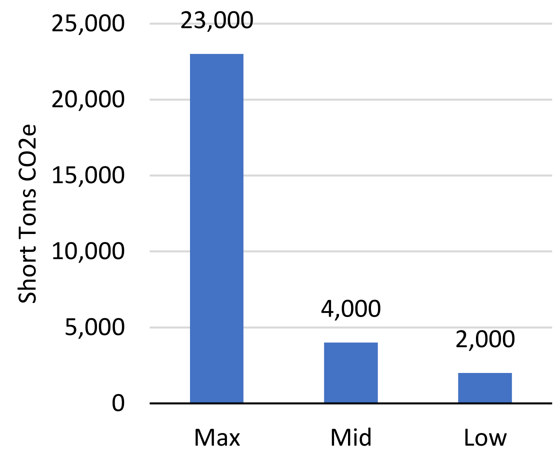


Figure 5-11. Average Greenhouse Gas Emissions Reductions Generated Each Year (2021-26; All Scenarios)



5.4 Sensitivity Analysis

The HE module is tested against electricity and fuel rate sensitivity scenarios.

As shown in Figure 5-12 and Figure 5-13, changes in future retail electric and fuel rates will impact customer propensity to pursue heating electrification. As electricity becomes cheaper or fuels become more expensive, customers are more likely to switch to heat pumps, while the inverse is true if electricity becomes more expensive or fuels become cheaper.

The impact is particularly pronounced when electricity rates are decreased or fuel rates are increased. Under these sensitivity scenarios, incremental lifetime savings increase by 87% to 91%, while savings decline by only 37% to 44% when electricity rates are increased or fuel rates are decreased. The proportional impact on program spending is significantly less than the impact on incremental savings, which suggests that customer adoption is impacted by cost-effectiveness to a large degree, meaning that even small changes in cost-effectiveness (e.g. decrease in electricity rates) will result in large changes in adoption.

Figure 5-12. Proportional Impact of Electric Rate Sensitivity on Incremental Lifetime HE Fuel Savings, Program Spending and Net Customer Benefits as Compared to Baseline (2021-26 Averages; Mid Scenario)

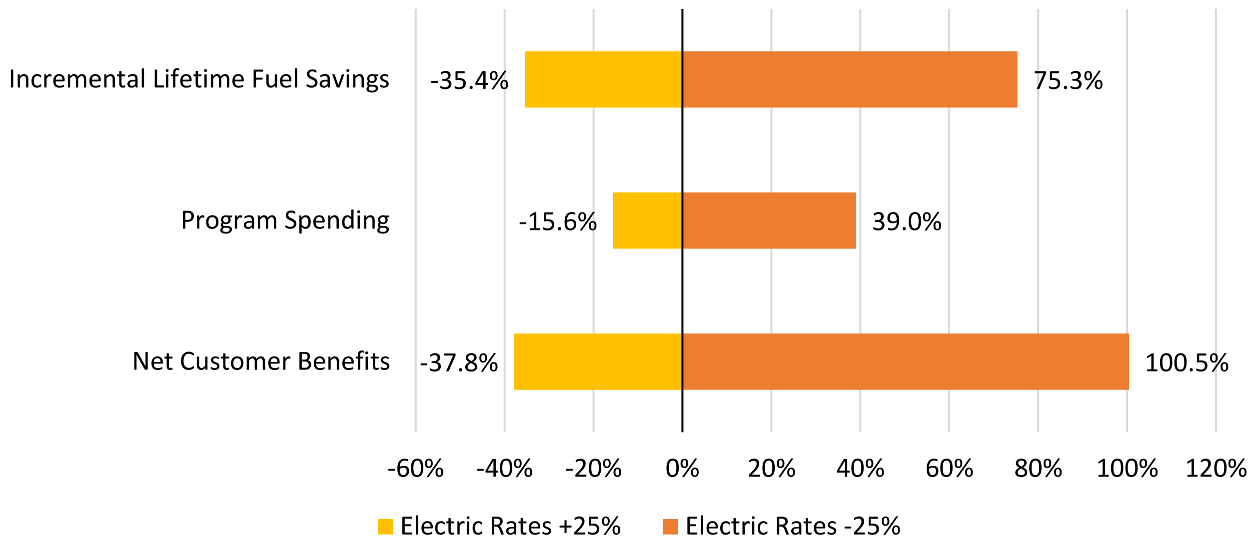
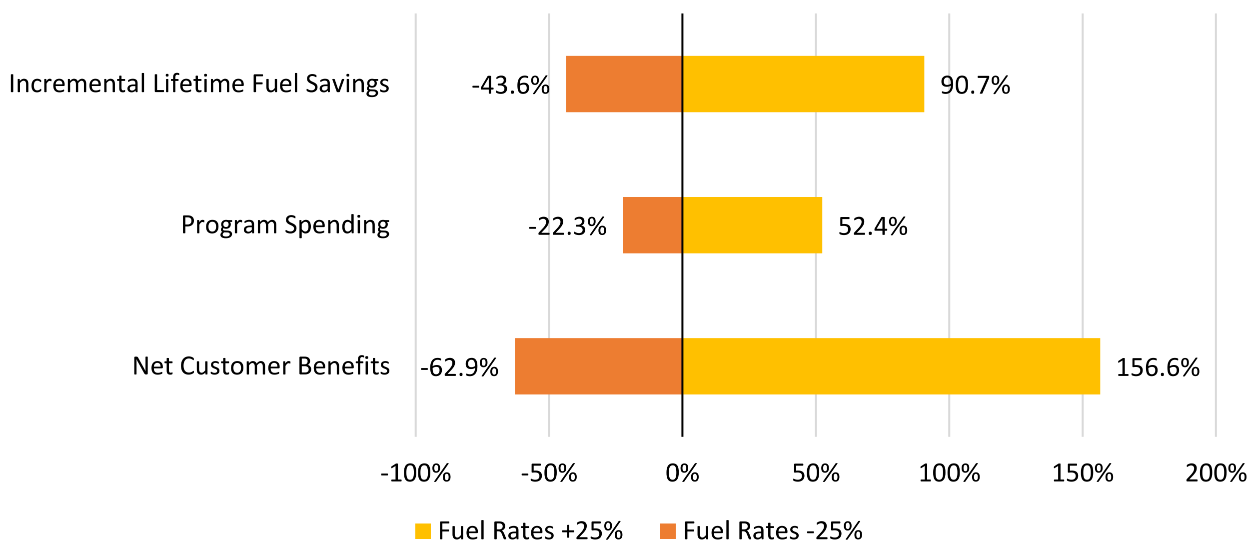
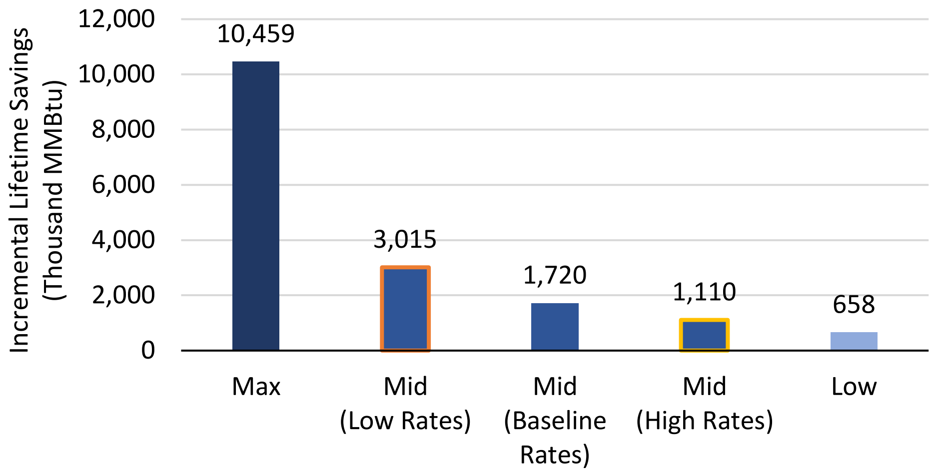


Figure 5-13. Proportional Impact of Fuel Rate Sensitivity on Incremental Lifetime HE Fuel Savings, Program Spending and Net Customer Benefits as Compared to Baseline (Mid Scenario)



In terms of absolute changes, the higher electric rate sensitivity decreases 2021-2026 average incremental lifetime savings to 1,110 thousand MMBtu per year and the lower rate sensitivity increases savings to 3,015 thousand MMBtu as shown in Figure 5-14.

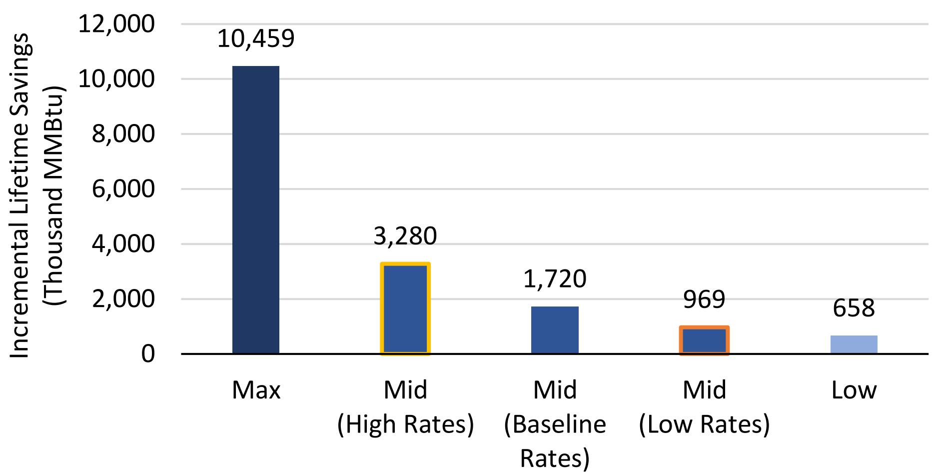
Figure 5-14. Average 2021-26 Incremental Lifetime HE Fuel Savings for Mid Scenario under Electric Rate Sensitivity



Note: Results for Max and Low scenarios in above figure are under baseline rates and provided for comparison purposes.

For the fuel rate sensitivity, higher fuel rates increase 2021-2026 average incremental lifetime savings to 3,280 thousand MMBtu per year and the lower rate sensitivity decrease savings to 969 thousand MMBtu as shown in Figure 5-15.

Figure 5-15. Average 2021-26 Incremental Lifetime HE Fuel Savings for Mid Scenario under Fuel Rate Sensitivity



Note: Results for Max and Low scenarios in above figure are under baseline rates and provided for comparison purposes.

5.5 System Impacts

The following section presents the HE module's results in terms of *cumulative savings* to provide an assessment of system level impacts resulting from heating electrification programs. As described in Chapter 1, cumulative savings are a rolling sum of all *new* savings from measures that are incentivized by efficiency programs. Cumulative savings provide the total expected impact on energy sales and electric peak demand overtime and are used to determine the impact of efficiency programs on long-term energy consumption and peak demand.

This section also provides cumulative results for technical and economic potential in addition to achievable scenario potential. There are two key caveats for understanding the technical and economic potential as presented in this section.

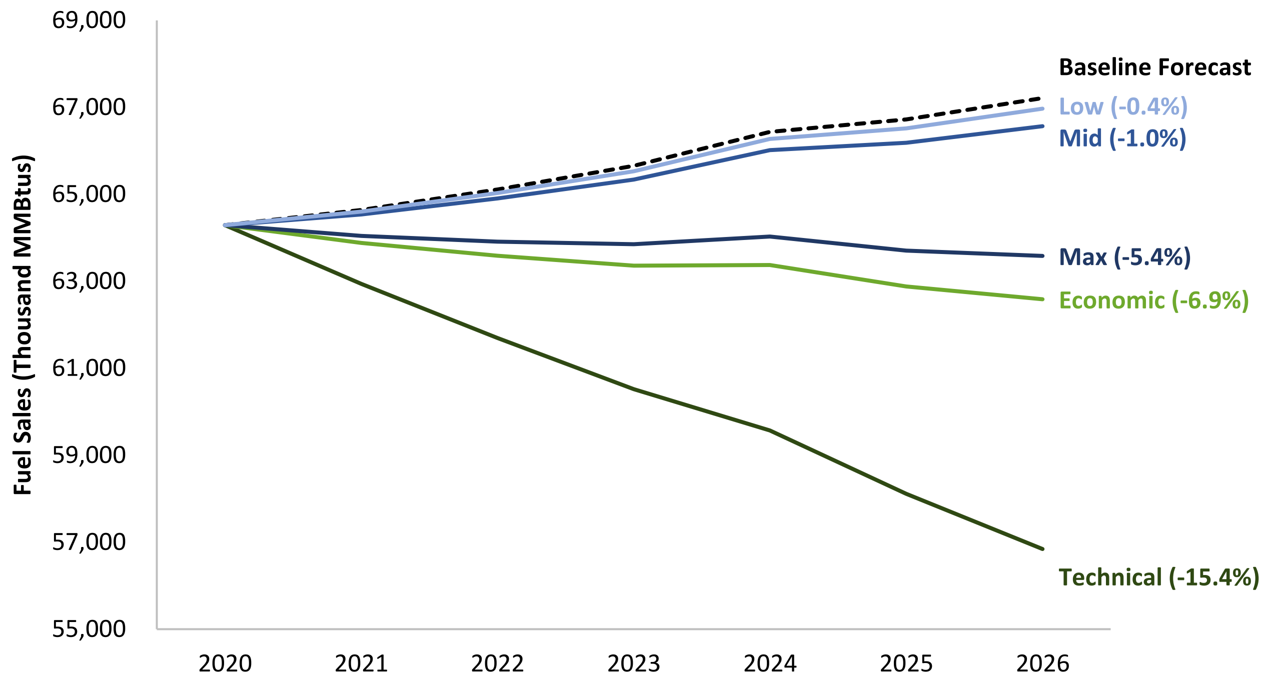
First, the **DEEP model estimates all potentials (technical, economic, and achievable) on an annual phased-in basis**. The model assumes that most efficient measures are not eligible for deployment until the existing equipment it is replacing reaches the end of its useful life or becomes a viable early replacement measure. This limits the number of opportunities available for efficiency upgrades each year. For this reason, technical and economic potential will increase each year of the study as more baseline equipment is eligible to be replaced.

Second, **technical potential in the HE module is constrained to the savings possible from the representative use cases** included in the study and does not represent all *technologically possible* savings. As explained further below and in Appendix B, the representative use cases characterize the most commercially viable electrification opportunities for each sector within the study period. This methodological choice

5.5.1 Fuel Impacts

By 2026, heating electrification could reduce forecasted combustible fuel (natural gas, oil, and propane) sales in Rhode Island by 243 thousand MMBtu (Low) to 3,629 thousand MMBtu (Max). This would reduce overall forecasted consumption of combustible fuels by 0.4% to 5.4%, respectively, as shown in Figure 5-16. If all economic savings were captured, combustible fuel consumption would decline by approximately 4,626 thousand MMBtu (6.9% of sales), and if all technical savings were captured, combustible fuel consumption would decline by 10,370 thousand MMBtu (15.4% of sales).

Figure 5-16. Impact of HE on Forecasted Fuel Sales (2021-26; Technical, Economic, and Program Scenarios)



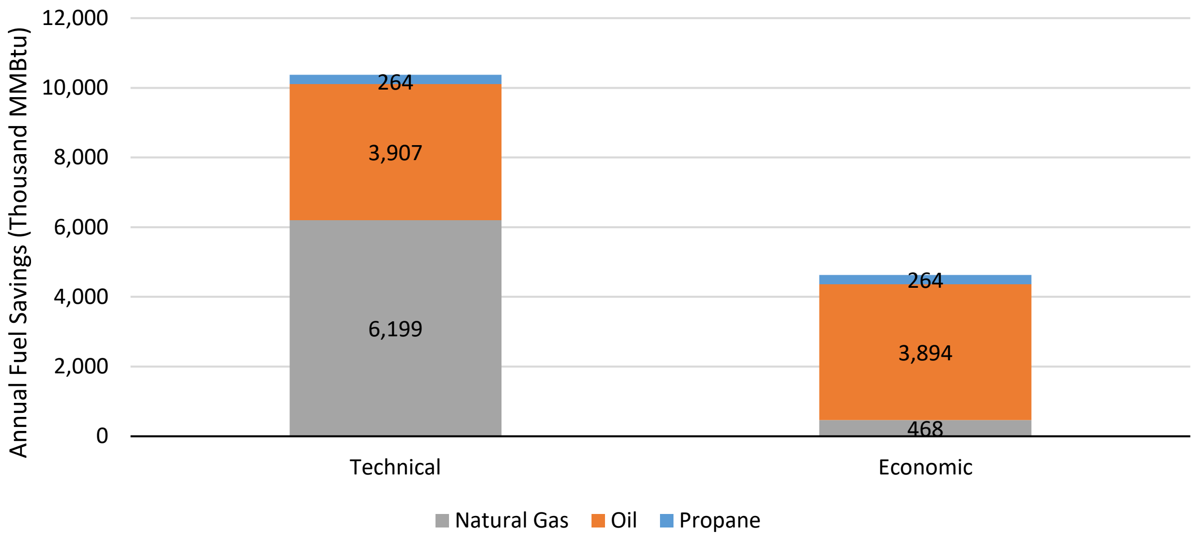
Note: Savings only represent natural gas and delivered fuel savings and do not include net increases in electricity consumption resulting from heating electrification.
Note: Y-axis in above figure does not begin at zero.

From these results, the following observations can be made:

A significant amount of technical HE potential is not economic. Cumulative economic potential is approximately 44.6% of technical potential. This is a result of most savings resulting from displacing existing gas heating systems with heat pumps not passing economic screening.

As shown in Figure 5-17, the majority of technical potential comes from displacing existing gas fired systems, which is driven by the higher prevalence of gas fired heating in RI homes and businesses, relative to delivered fuels. However, only 7.6% of the gas savings pass the economic screen to be included in economic potential, while 100% of propane technical potential and 99.7% of oil technical potential passes cost effectiveness screening. This difference is due to relatively higher avoided costs for oil and propane relative to natural gas. On a per MMBtu basis, the avoided costs for propane and oil are approximately two to three times greater than natural gas, respectively.

Figure 5-17. Cumulative Technical and Economic HE Potential by Fuel Type (2026)

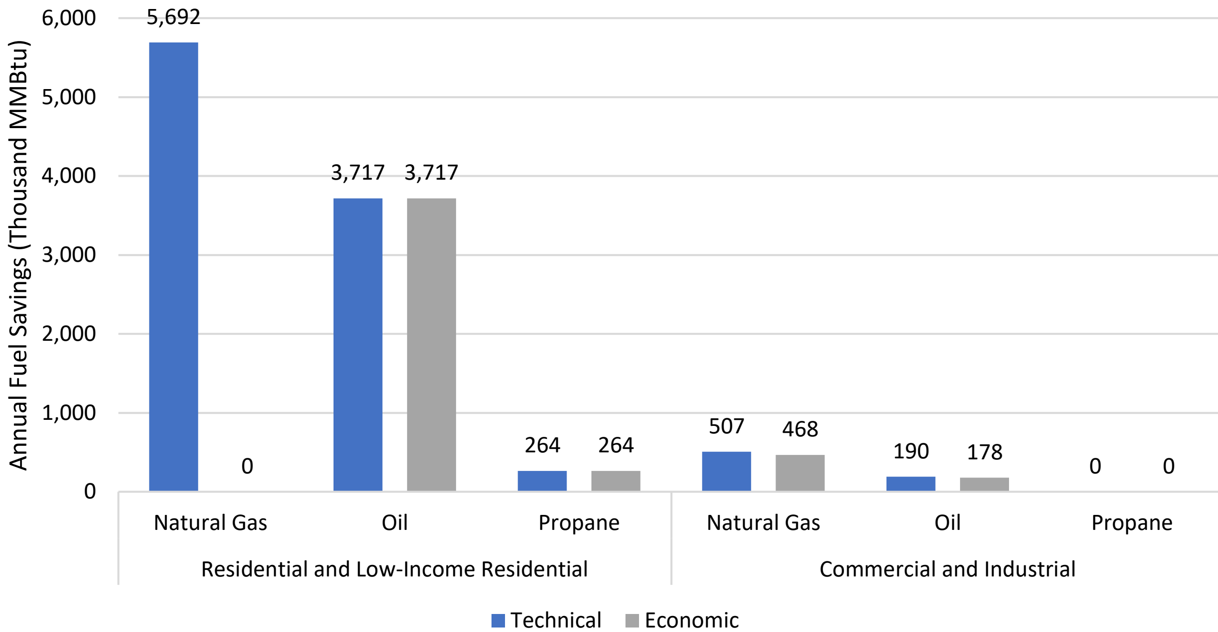


Note: Savings only represent natural gas and delivered fuel savings and do not include net increases in electricity consumption resulting from heating electrification.

As shown in Figure 5-18, the only gas fired heating system replacements that pass economic screening are in the C&I market and that the extent of the technical potential for these measures is much less than in the residential market. Both these observations are largely driven by the assumption that C&I customers will size heat pumps primarily based on their cooling capacity needs in order to maximize the benefit/cost ratio of the new systems. This reduces the average heat pump sizing in the C&I market, which in turn leads to a smaller portion of heating load being served by the heat pump than in the residential market[73]. This assumption also supports lower incremental costs and higher utilization factors for heating electrification equipment in the C&I markets, as the adoption of heat pumps defers the need to invest in air conditioning equipment and these systems will tend to run more hours per year, which improves the benefit-cost value of these measures.

[73] This study applies an assessment of the commercially viable technical potential that assumes C&I customers would install heat pumps that are sized to meet 100% of their cooling needs, but not their full peak heating needs. Thus, the technical potentials are somewhat lower than the full technically possible HP capacities needed to electrify all heating demand in C&I buildings. This assumption was applied to avoid overburdening the benefit/cost assessment with the full heating load HP replacement costs, which would thereby lead to few or no non-residential systems passing the RI Test screen.

Figure 5-18. Cumulative Technical and Economic HE Potential by Sector and Fuel Type (2026)

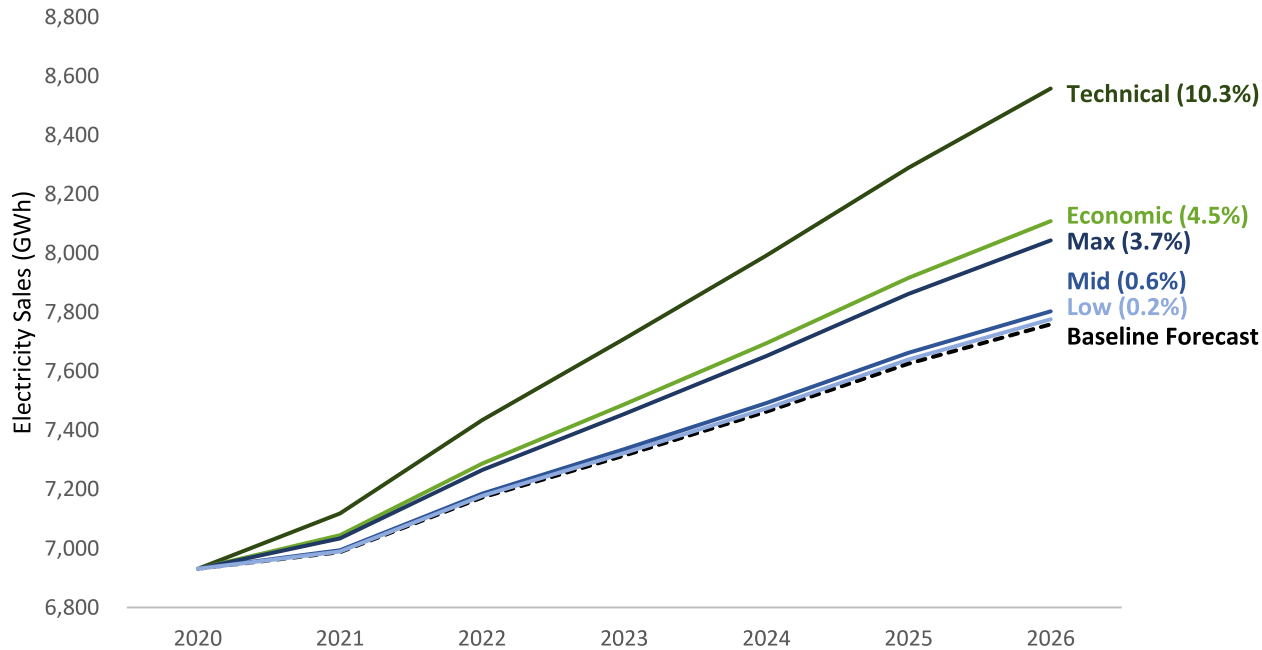


Achievable potential is highly constrained by customer economics. Under the Low scenario, which applies a 25% customer incentive, only 5.3% of cumulative economic savings are captured while the Mid scenario captures 14.0% of economic savings when incentive levels are increased to 50%. Conversely, the Max scenario captures 78.5% of economic savings representing a nearly six-fold increase in savings over the Mid scenario. This result suggests that the incremental costs of replacing existing fueled heating systems with heat pumps is a significant impediment to customer adoption.

5.5.2 Electric Impacts

While heating electrification will result in significant on-site fossil fuel savings, it will also lead to notable increases in electricity consumption. By 2026, heating electrification could increase electricity consumption by 17 GWh (Low) to 284 GWh (Max). Overall, heating electrification would increase forecasted electricity sales by 0.2% to 3.7%, respectively, as shown in Figure 5-19. These impacts are net of any savings resulting from more efficient space cooling.

Figure 5-19. Impact of HE on Forecasted Electricity Sales (2021-26; Technical, Economic, and Program Scenarios)

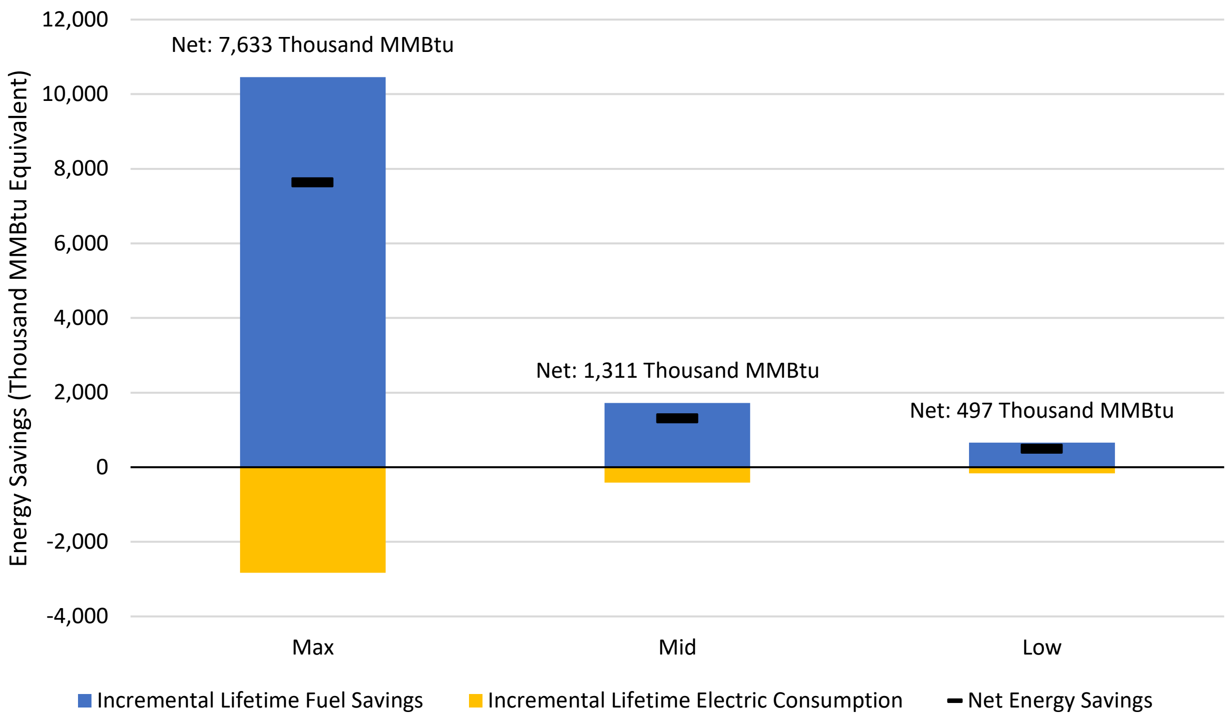


Note: Y-axis in above figure does not begin at zero.

Even though heating electrification will increase electricity consumption, heat pumps considered here deliver a net reduction in overall site energy consumption when electricity and combustible fuels are considered together. Heat pumps can produce useful thermal energy at effective efficiencies in excess of 300% since they use electricity to transfer heat from another medium (e.g. outside ambient air in the case of air source heat pumps) to the conditioned space. Meanwhile, conventional systems such as combustible fuel furnaces and boilers typically have efficiencies in the range of 70% to 90%. This difference in system efficiencies results in significant net energy savings when electricity and fuel consumption are compared on an MMBtu basis.

Figure 5-20 shows the average net incremental lifetime savings of HE programs under each scenario in terms of MMBtu equivalent. As can be seen, fuel savings far outweigh the increase in electricity consumption.

Figure 5-20. 2021-26 Average Annual Net Lifetime Energy Savings (All Scenarios)



Note: Results in figure are presented in terms of energy savings. Negative values denote an increase in consumption.

Table 5-6 shows the incremental lifetime fuel savings and electric consumption for each year of the study period under each scenario in common energy terms.

Table 5-6. HE Incremental Lifetime Savings for All Fuels, Incremental Lifetime Electric Consumption, and Lifetime Net Energy Savings by Year (All Scenarios)

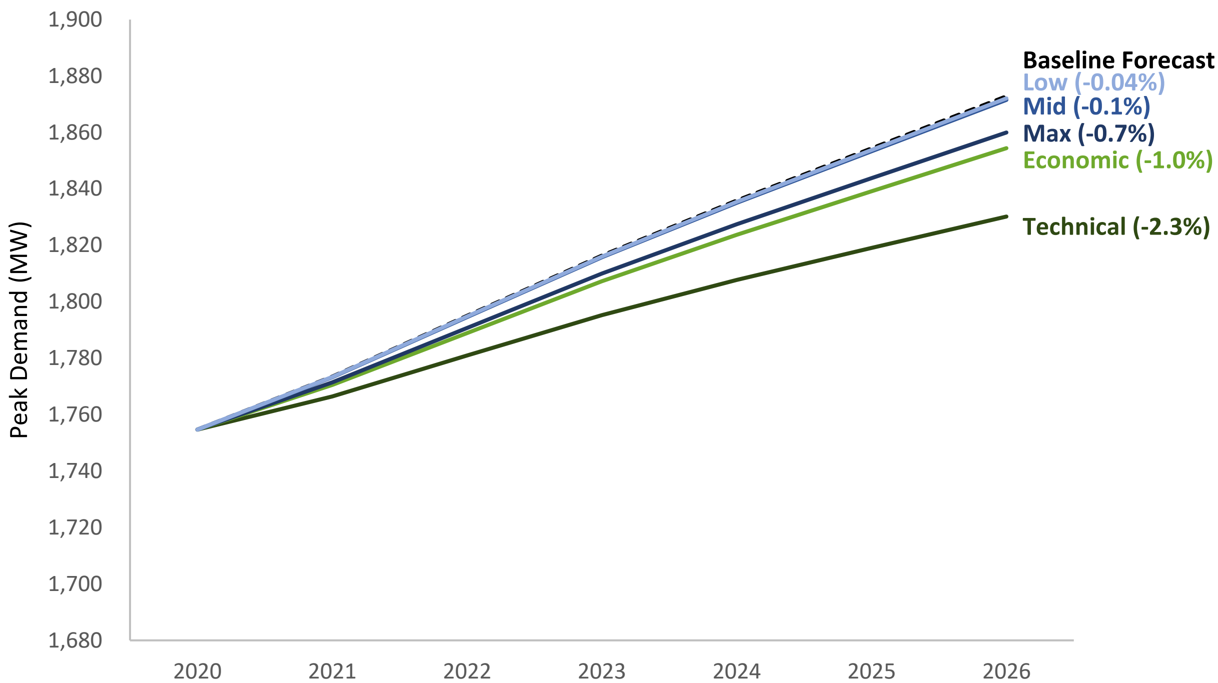
Program Savings	Scenario	2021	2022	2023	2024	2025	2026	*Average*
Lifetime Fuel Savings (Thousand MMBtu)	Max	10,311	10,363	10,415	10,467	10,519	10,678	**10,459**
	Mid	1,618	1,659	1,706	1,743	1,781	1,811	**1,720**
	Low	634	643	654	662	671	683	**658**
Lifetime Electric Consumption (Thousand MMBtu equivalent)[74]	Max	-2,786	-2,800	-2,814	-2,828	-2,842	-2,885	**-2,826**
	Mid	-381	-393	-405	-415	-425	-432	**-409**
	Low	-156	-158	-160	-161	-163	-166	**-161**
Lifetime Net Energy Savings (Thousand MMBtu Equivalent)	*Max*	*7,525*	*7,563*	*7,601*	*7,639*	*7,677*	*7,793*	***7,633***
	Mid	*1,237*	*1,266*	*1,301*	*1,328*	*1,356*	*1,379*	***1,311***
	Low	*479*	*486*	*494*	*500*	*507*	*517*	***497***

Note: Results in table are presented in terms of energy savings. Negative values denote an increase in consumption.
Units: Thousand MMBtu

[74] Electric consumption kWh are converted to MMBtu at a conversion rate of 0.0034121 kWh per MMBtu.

Contrary to an increase in overall electricity consumption, heating electrification typically results in a reduction in overall electric peak demand in Rhode Island as the study assumes the majority of heat pumps adopted for space heating electrification will also provide more efficient space cooling than existing air conditioning systems and Rhode Island is a summer peaking system. By 2026, heating electrification could decrease peak demand by 0.7 MW (Low) to 12.8 MW (Max) resulting in an overall reduction in peak demand of 0.04% to 0.7%, respectively, as shown in Figure 5-21.

Figure 5-21. Impact of HE on Forecasted Peak Electric Demand (2021-26; Technical, Economic, and Program Scenarios)



Peak demand savings will not result for every customer that chooses to electrify space heating. In the residential sector, the choice to electrify space heating will result in a net increase in peak demand for customers that do not currently have air conditioning and would not be expected to adopt air conditioning during the study period in the absence of heating electrification. The study assumes these customers will use their heat pumps for space cooling purposes as well – contributing to summer peak demand. Overall, however, this impact is relatively small. By 2021, the study assumes approximately 82% of residential customers will have some form of air conditioning (see Appendix B for more information on assumptions underlying AC adoption in Rhode Island). Of the 18% that do not have air conditioning at the beginning of 2021, the study assumes 45% of these customers will adopt air conditioning based on current growth in air conditioning penetration in Rhode Island. This leaves just a small fraction of the total residential population that would contribute additional peak demand when participating in HE programs. Under the Mid scenario, residential customers without air conditioning would be expected to increase peak demand by only 160 kW by 2026, while customers with pre-existing air conditioning systems (or who plan to install air conditioning) would decrease peak demand by 1,340 kW by choosing a heat pump instead of a standard AC unit.[75]

5.6 Key Takeaways

Based on the results presented in this chapter, the following key take-aways emerge:

Electrifying oil and propane-based systems offers the bulk of the economic opportunity for heating electrification. The higher avoided costs of oil and propane result in greater benefits that outweigh the additional cost of heat pump systems and electricity consumption. For most applications, electrifying natural gas-based systems does not pass economic screening.

For residential customers, large incentives are needed if significant market transformation is to be achieved. Compared to the increase in savings between the Low and Mid scenarios where incentives are increased from 25% to 50%, there is a much more significant increase in achievable fuel savings between the Mid and Max scenarios where incentives are increased from 50% to 100% of incremental costs. This suggests that large up-front incentives in excess of 50% of the incremental cost of heat pump space heating systems are needed to drive large numbers of residential customers to electrify their heating systems.

Heating electrification creates significant net benefits for Rhode Island. The benefits from avoided fuel consumption and decreasing electric peak demand will far outweigh the costs of increased electricity consumption. The greater efficiency of heat pumps relative to fossil-fuel based systems results in the reduction of overall net customer energy consumption, and the addition of heat pumps for space heating will provide more efficiency space cooling to Rhode Island homes and businesses as well.

[75] While this analysis did not include an assessment of winter peak load impacts since Rhode Island is currently (and expected to remain) a summer peaking system, the adoption of electric heat pumps to displace existing fossil fuel systems would be anticipated to increase winter-time peak loads.

6 Customer-Sited Solar PV

6.1 Overview

The following chapter presents results for customer-sited solar photovoltaics (PV) module of the market potential study (MPS). This module assesses the technical, economic, and achievable potential for customer-sited rooftop solar systems in Rhode Island during the study period. In addition to the assessment of solar potential, the analysis also includes a forecast of storage-paired solar deployment in Rhode Island during the study period. Additionally, a meta-review of value of solar studies is conducted to provide a benchmark for the value that distributed solar uptake brings to the grid.

6.1.1 Approach

To assess the technical, economic, and achievable potential for building-sited rooftop solar systems in Rhode Island, the following approach is used:

- **Technical Potential:** Using the market segments developed for this study to breakdown Rhode Island households and businesses with similar decision-making thresholds, building characteristics, energy consumption, pricing and other characteristics, the technical potential for solar deployment in the state is estimated. For each segment, the theoretical maximum achievable potential for rooftop solar is calculated based on estimates of the number of suitable sites for solar deployment, average PV system sizes, and energy generation potential for a typical solar system. Additionally, outcomes of other Rhode Island specific studies are used to validate and arrive at a final estimate of technical potential for solar deployment.
- **Economic Potential:** To assess the economic potential, the benefits and costs associated with the identified technical potential are computed using the RI Test for cost-effectiveness.
- **Achievable Potential:** The study leverages Dunsky's Solar Adoption Model (SAM) and Rhode Island-specific inputs to forecast solar adoption and the corresponding load (i.e. energy and demand) and program (e.g. program uptake, incentive costs) impacts under a number of scenarios reflecting different market and policy conditions. To capture local market characteristics, the model is calibrated to the Rhode Island solar market using historical inputs and adoption trends.

Detailed model methodology and study approach as well as key inputs and assumptions used in the study are presented in Appendix E.

Virtual Net Metering

While the scope of the study focuses on customer-sited rooftop solar adoption, other forms of solar adoption are expected to play a role in the future – specificallyy, the growing interest in Virtual Net Energy Metering (VNEM). VNEM enables customers to subscribe to solar projects (installed at another location) and benefit from bill credits corresponding to their share of the system's production, even if the system is not physically sited on a customer's premises. While building-sited solar adoption remains a popular choice, VNEM can increase adoption in other market segments by alleviating barriers they face. For example, community solar projects provide households and businesses who lack suitable rooftops (e.g. residents of multi-unit residential buildings) with access to solar. Additionally, the projects often benefit from economies of scale due to the larger system size and lower capital requirements (due to the ability to purchase/subscribe to smaller increments) which can remove barriers facing lower-income households.

In Rhode Island, VNEM is enabled through a 30 MW allocation for Community Remote Net Metering (CRNM) as well as the Net Metering tariff, which allows public entities (e.g. municipal, state, quasi-state) to enter into VNEM arrangements. At the end of 2019, nearly 25 VNEM systems with a capacity of 72 MW were installed in Rhode Island and an additional 86 (500 MW) were pending interconnection.[76]

6.1.2 Program Scenarios

Advancements in PV technologies coupled with cost reductions, strong federal and state policy support, and increasing customer interest in choice and self-supply have spurred a significant increase in customer-sited solar systems. At the end of 2019, more than 7,000 homes and 400 businesses had installed solar systems on their premises in Rhode Island with a total installed capacity of nearly 200 MW.[77]

To explore the adoption of customer-sited solar PV in Rhode Island, the study models the impact of three scenarios that reflect different market and policy conditions. Specifically, the three scenarios consider the following factors[78]:

- **Renewable Energy Growth (REG) Program:** Annual allocation caps for the REG program will determine the overall market uptake of solar under this program as well as the distribution between REG and Net Energy Metering (NEM) installations.
- **Renewable Energy Fund (REF) Incentives:** Future value and timing of rebates offered by the REF program to NEM systems will impact market trajectory in the short-term.
- **PV System costs:** Future system costs, particularly in the context of the phase-out of Federal Investment Tax Credit (ITC), exhibit significant uncertainty and will impact future adoption trends.

[76] Office of Energy Resources (2019), Rhode Island Distributed Generation Solar Updates. ISO New England presentation (available online).
[77] Based on National Grid Interconnection data provided in October 2019 and adjusted to account to end-of-year uptake.
[78] Detailed scenario assumptions are presented in Appendix F.

Given that existing program support for solar PV in Rhode Island is significant, existing programs are modeled as the Mid scenario ("Base Case"). Additional scenarios featuring reduced (Low) and more aggressive (Max) programs are modeled as described in Figure 6-1. Given that the federal Investment Tax Credit (ITC) incentive levels will be stepped down during the study period (from 26% in 2020 to 0% and 10% by 2022 for the residential and non-residential sectors, respectively) the scenarios are designed to reflect the market trajectory after the ITC phase-out.

Figure 6-1. Solar Program Scenario Descriptions

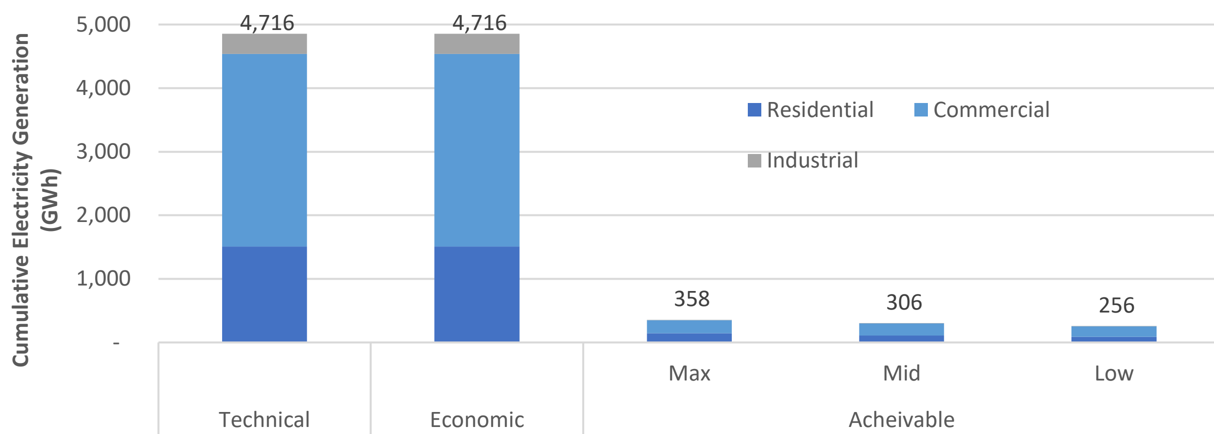
Low	**Reduced policy support for solar deployment** and unfavorable market conditions after the phase-out of Federal Investment Tax Credit (ITC). • REG program with constrained allocation • Net-Metering with no upfront incentives • High system costs post ITC phase-out
Mid	**Business-as-usual policy support and market conditions** for solar in Rhode Island that maintains the trajectory of current programs • REG program with existing allocation • Net-Metering with BAU incentives levels (stepped-down) • BAU system costs post ITC phase-out
Max	**More aggressive policy support and favorable market conditions** for solar deployment in Rhode Island to counteract the impacts of the phase-out of the ITC. • REG program with no allocation caps • Net-Metering with BAU incentives (stepped-down gradually to mitigate ITC Phase-out) • Low PV costs post ITC phase-out

6.1.3 Summary of Results

The analysis of the technical potential for customer-sited solar deployment in Rhode Island highlights 4 GW of potential solar capacity, corresponding to 4.7 TWh of annual electricity production. Using the RI Test, all technically feasible solar deployment is found to be cost-effective.[79] Within the study period, the modeled achievable potential scenarios show that 195 MW (Low) to 273 MW (Max) of customer-sited solar PV are forecasted to be deployed in Rhode Island. The forecasted uptake will correspond to between 256 GWh (Low) and 358 GWh (Max) of electricity generation from customer-sited solar PV by 2026, which corresponds to approximately 3.3% to 4.6% of forecasted electricity sales in 2026. Due to larger rooftop areas available for solar installation, the majority of the potential for customer-sited solar deployment is in the commercial sector as shown in Figure 6-2.

[79] For a full description of the benefits and costs included in the RI Test, please see the Attachment 4 - 2020 Rhode Island Test Description as filed with National Grid's 2020 EEPP (Docket No. 4979) accessible at: http://www.ripuc.ri.gov/eventsactions/docket/4979-NGrid-EEPP2020%20(10-15-19).pdf

Figure 6-2. Summary of Customer-sited Solar Potential in Rhode Island (2021-2026)

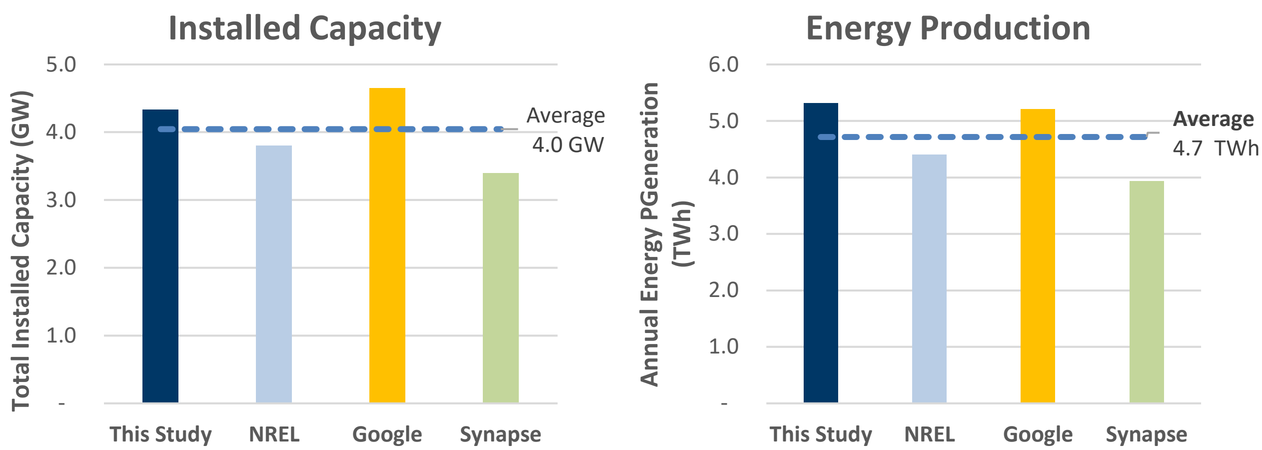


6.2 Technical and Economic Potential

To estimate the technical potential for solar deployment in Rhode Island, the theoretical maximum potential for rooftop solar PV in each segment is calculated using data on the number of suitable sites, average system sizes, and energy generation potential for a typical system. Given that the analysis on the technical potential in this study does not use geographic information system (GIS) data, additional sources that have quantified solar deployment potential using granular geospatial analyses were used to benchmark and adjust the study's estimate. Specifically, Rhode Island specific data from the National Renewable Energy Laboratory (NREL), Google's Project Sunroof and draft results from a study conducted by Synapse Energy for the Rhode Island Office of Energy Resources (OER) are leveraged to estimate technical potential for distributed solar deployment in Rhode Island. As shown in Figure 6-3, the solar technical potential estimates from the four studies range from 3.4 GW to 4.6 GW. Differences in the estimated potential can be largely attributed to the use of different data sources, approaches and assumptions across the studies.

To arrive at a reasonable estimate of technical potential, the average of the results from the four sources is used to determine the technically feasible potential for solar deployment in Rhode Island. **The analysis indicates that 4 GW of building-sited rooftop solar capacity can be installed producing 4.7 TWh in energy annually.** Nearly 60% of the identified technical potential is estimated to be in the commercial sector, with the remaining being residential and limited potential in the industrial sector, as shown earlier in Figure 6-2.

Figure 6-3. Technical Potential for Customer-Sited Solar PV Deployment in Rhode Island



To assess the economic potential, the identified technical potential for solar deployment is screened using the RI Test. The RI Test provides a full assessment of the value of load reduction measures in Rhode Island through the inclusion of a comprehensive set of quantifiable benefit streams attributable to energy saving programs.[80] **Considering the benefits and costs associated with customer-sited solar deployment, 100% of identified technical potential is found to be cost-effective.**

[80] For a full description of the costs and benefits included in the RI Test, please see the Attachment 4 - 2020 Rhode Island Test Description as filed with National Grid's 2020 EEPP (Docket No. 4979) accessible at: http://www.ripuc.ri.gov/eventsactions/docket/4979-NGrid-EEPP2020%20(10-15-19).pdf. The study does not consider the feedback between solar adoption and avoided costs. Such an analysis was not within the scope of the study.

Synapse Energy Economics Study

The Office of Energy Resources (OER) commissioned Synapse Energy Economics to conduct a study assessing the technical and economic potential for solar PV systems across Rhode Island. The following list describes the differences between this analysis and the Synapse study to facilitate comparison and interpretation of key results from each study:

- Research Question and Scope: The core focus of the Synapse study is a granular assessment of the technical potential for solar PV across Rhode Island, which was identified through GIS analysis, while this study considers achievable potential in more detail.
- Coverage: The Synapse study includes an assessment of rooftops, landfills, gravel pits, brownfields, carports and commercial/industrial parcels, while this study only considers rooftop solar potential.
- Technical Potential Approach: This study uses a desk-review approach to estimate the technical potential using building counts and sizes from the Energy Information Agency's (EIA) Commercial Building Energy Consumption Survey (CBECS) coupled with assumptions from NREL and Google tools, whereas the Synapse study uses detailed building shapes and lidar data to map solar potential by municipality. Overall, the technical potential from this study and Synapse study fall within a reasonable range (3.4 GW versus 4.3 GW).
- Definition of Economic Potential: The Synapse study defines economic potential from the perspective of customers adopting solar using current system costs and program incentives, whereas this study assesses cost-effectiveness using benefits and costs from the RI Test. Therefore, Synapse's economic potential and the economic potential from this study are not directly comparable. Additionally, this study assesses the economic potential across all customer-sited rooftop segments, whereas the Synapse study only considers the economic potential of rooftop deployment within the residential sector.
- Time horizon: This study estimates achievable potential over the period of 2021 to 2026, while the Synapse study offers a "snap-shot" into the technical and economic potential today.
- Scenarios: The Synapse study considers current programs and PV costs to assess economic potential, whereas this study considers projected policy and market conditions relating to REG program price and allocation caps, REF Program incentive levels and solar PV system costs between 2021 and 2026, and assesses their impact on achievable potential.

6.3 Achievable Potential

This section presents forecasted customer-sited solar uptake under the three modeled achievable potential scenarios. Overall, the results indicate that the achievable market potential will depend on policy and market response after the ITC phase-out and will vary between 195 MW (Low) to 273 MW (Max) of deployed capacity over the study period, corresponding to 256 GWh (Low) to 358 GWh (Max) of energy production from additional customer-sited solar adoption by 2026.

Impacts of COVID-19

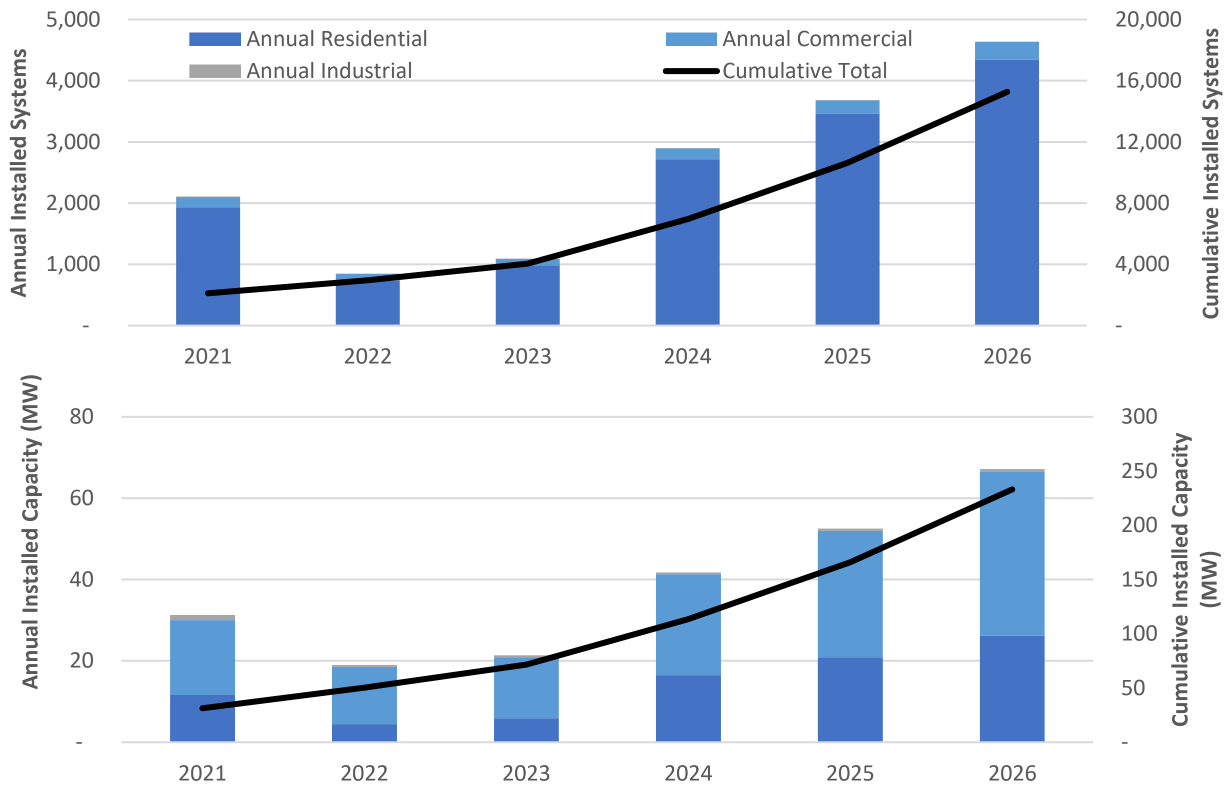
The MPS was conducted prior to the onset of the COVID-19 pandemic in the first quarter of 2020. Accordingly, **the study does not explicitly consider the implications COVID-19 will have on achievable savings potentials**. While COVID-19 is likely to have an impact on the achievable potential scenarios in the short-term, there remains significant uncertainty around the longer-term impacts. In particular, the abrupt drop in demand for solar PV may break the momentum the market has gained from strong policy and program support for PV as well as hurt the local solar industry in the state, reducing workforce and capacity to meet future demand. Further analysis will be required to understand the impacts COVID-19 may have on solar deployment in Rhode Island.

6.3.1 Base Case (Mid Scenario)

The Mid scenario represents forecasted solar adoption in Rhode Island under a business-as-usual scenario where customers have access to the REG and REF programs. Both programs are assumed to step-down their incentive levels gradually over the study as per historical trends.

Under this scenario, 15,300 new customer-sited solar systems, corresponding to 233 MW of solar capacity, are forecasted to be installed in Rhode Island over the study period (2021-2026). The majority of the installed systems (93%) are forecasted to be residential, however residential installs will only represent 37% of total installed capacity due to the larger sizes of commercial systems. Additionally, limited solar uptake is observed in the industrial sector, which is in-line with historical trends observed in the state.

Figure 6-4. Installed Customer-Sited Solar Systems and Capacity under the Base Case (Mid Scenario)

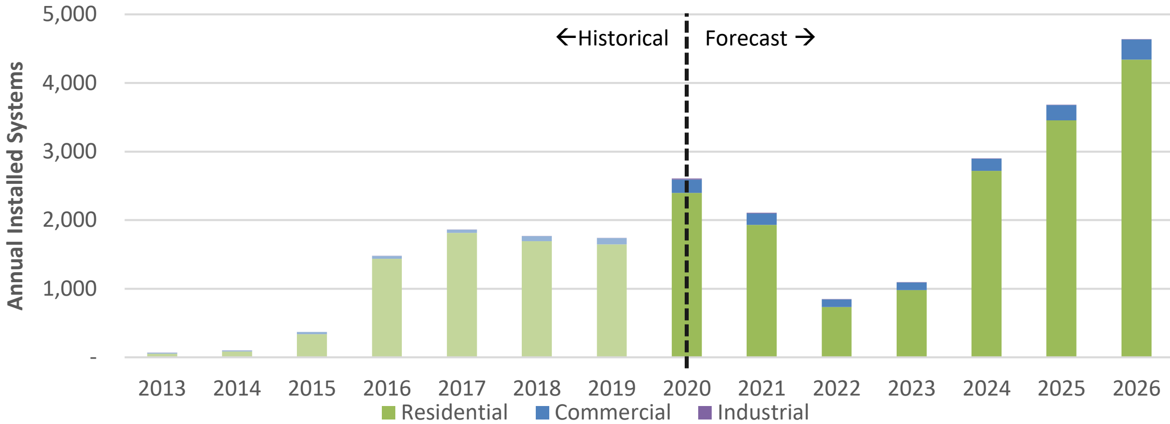


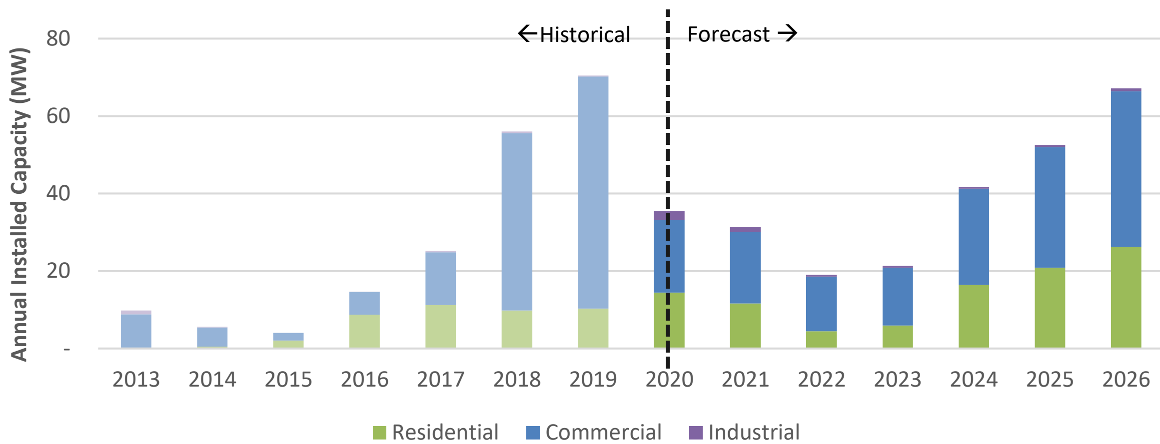
The market is expected to slow down in the short-term due to the phase-out of the Federal ITC. A notable drop in solar uptake is observed in 2022 and 2023 with the incentive phase-out as economics for potential adopters worsen. Generally, the impacts on the ITC phase-out are expected to be more pronounced in the residential sector relative to the non-residential sector, due to the continuing 10% incentive for commercial applications. After a 2-3-year period with reduced solar demand, annual solar deployments are expected to return to historical levels as the economics improve due to falling solar PV costs.

6.3.1.1 Comparison to Historical Adoption

Figure 6-5 below compares forecasts under the Mid scenario to historical uptake from National Grid's interconnection data. The comparison shows that a significant drop in solar PV system adoption is expected to be observed between 2021 and 2023 as a result of the ITC phase-out, however the market is expected to pick up and return to historical deployment levels by 2024. However, despite an increase in the number of systems installed in 2021 and in later years of the study (2024 – 2026) relative to historical uptake, forecasted annual installed capacity (MW) is estimated to be below historical levels in the short-term. This is a result of a reduction in average system sizes over time in the commercial sector as increased adoption by smaller mass-market commercial customers results in smaller system sizes compared to those installed by early adopters and larger commercial customers.

Figure 6-5. Historical and Forecasted Annual Installations and Capacity (Mid Scenario)





6.3.1.2 Load Impacts

The forecasted customer-sited solar in Rhode Island has the potential to reduce electricity sales by displacing customers' electricity consumption with the energy generated from the installed solar systems. Additionally, the high coincidence between solar generation profiles and the state's load patterns provides an opportunity to reduce electric peak demand.

As shown in Table 6-1, under the Mid scenario, forecasted adoption will contribute to 306 GWh of energy savings in 2026 (i.e. reduction in energy sales/consumption in that year) as well as a 63 MW reduction in peak demand in the same period. This corresponds to approximately 3.9% of forecasted electricity sales in 2026. Over the lifetime of the systems forecasted to be installed during the study period, 8,780 GWh of energy consumption will be avoided between 2021 and 2056. In total, this forecasted generation will result in significant emission reductions. Customer-sited solar PV systems installed during the study period under the Mid scenario will reduce emissions by 144 thousand short tons of carbon-dioxide equivalent

(tCO_2e).[81] This is equivalent to removing approximately 28,200 passenger vehicles from the road for a year.[82]

Table 6-1. Load Impacts of Customer-Sited Solar Deployment under the Mid Scenario

Savings	Sector	2021	2022	2023	2024	2025	2026
Cumulative Savings (GWh)[83]	Residential	15	21	28	49	76	110
	Commercial	25	43	63	96	137	191
	Industrial	2	2	3	4	5	5
	Total	41	67	95	149	218	306
Cumulative Peak Savings (MW)	Total	7	20	25	35	47	63

Table 6-2. Lifetime energy savings from Customer-Sited Solar Deployment under the Mid Scenario

Savings	Sector	2021	2022	2023	2024	2025	2026	Average	Total
Incremental Lifetime Savings (GWh)[84]	Residential	434	162	217	606	769	964	525	3 ,152
	Commercial	706	540	568	947	1,183	1,528	912	5,472
	Industrial	52	19	19	19	21	26	26	156
	Total	1,191	721	805	1,572	1,974	2,518	1,463	8,780

Table 6-3. Cumulative and Lifetime Emission Reductions from Customer-Sited Solar Deployment under the Mid Scenario

Metric	2021	2022	2023	2024	2025	2026	Total
Cumulative Emission Reductions (tCO_2e)	19,501	31,303	44,480	70,217	102,539	143,777	N/A
Lifetime Emission Reductions (tCO_2e)	559,670	338,737	378,169	738,653	927,649	1,183,524	4,126,402

6.3.1.3 Programs

Households and businesses in Rhode Island interested in adopting solar PV systems have a choice between one of two incentive programs.

- The REG Program, which provides a long-term (15-20 year) contract that guarantees payment for energy produced from their systems[85], or

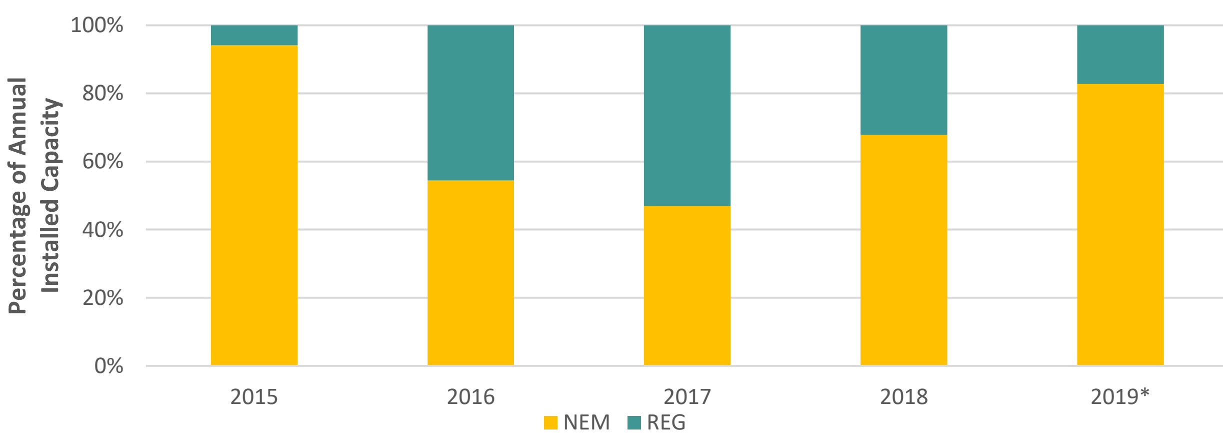
[81] Emission reductions are estimated using emission factors from the *Avoided Energy Supply Components (AESC) in New England: 2018* report. See Appendix F for more details.
[82] Passenger vehicle estimate calculated using the EPA Greenhouse Gas Equivalencies Calculator accessible at: https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator
[83] *Cumulative savings* represent savings incurred in a given year from systems installed to date (considering only systems installed during the study period)
[84] *Incremental lifetime savings* represent the total lifetime savings incurred from a system installed in a given year.
[85] To capture full life-time benefits of installed systems, REG customers are assumed to be compensated at retail rates at the end of the lifetime of their contracts.

- The REF Program coupled with NEM, which provides a rebate to cover a portion of the upfront system costs and compensates customers for grid exports at the retail rate.

Given that customers can only opt in to one of the two programs, the study considers the competition between the two programs[86]. A competition function is applied to estimate the number of customers that would opt in for each program based on the economics of each program during the study period as well as historical market trends captured through the model calibration of both programs independently.

Overall, the results in Table 6-4 highlight increasing interest in NEM over the study period, in-line with observed trends over the past 3 years. While REG has contributed to significant growth in solar deployment in Rhode Island since its inception, the breakdown of historical uptake by program – shown in Figure 6-6 – highlights a decline in REG uptake relative to NEM over the past three years (2017-2019).

Figure 6-6. Breakdown of Historical Solar Uptake by Program



While nearly 60% of new solar installations in 2018 were under the REG Program, the share of REG is forecasted to decrease to 25% of new annual installed systems by 2026. Interest in REG is expected to be particularly low in the commercial sector, with the assumed annual program cap only being reached in the later years of the study period. Over the study period, nearly 70% of installed systems and capacity are expected to go through NEM due to the more favorable economics for adopting customers.

Table 6-4. Forecasted Customer-Sited Solar Uptake by Program (Mid Scenario)

Program	Metric	2021	2022	2023	2024	2025	2026	Average	Total
REG	Annual Installed Systems	737	311	490	1,067	1,157	1,230	832	4,991
	Annual Installed Capacity (MW)	8	4	7	14	16	18	11	66
NEM + REF	Annual Installed Systems	1,372	536	609	1,836	2,528	3,406	1,714	10,286
	Annual Installed Capacity (MW)	24	15	15	28	36	49	28	167
Total	Annual Installed Systems	2,109	847	1,099	2,903	3,685	4,636	2,546	15,277
	Annual Installed Capacity (MW)	31	19	21	42	53	67	39	233

[86] Effective April 1st 2020, REG systems may be paired with NEM systems on the same site to cover a customer's net usage not already covered by an existing DG system.

Program Costs

Considering the financial value of customer net metering and bill credits, incentive costs, and program administration costs, the study estimates program costs and committed spending under the Mid scenario as shown in Figure 6-7. Unlike upfront rebates and incentives paid out in a single program year, both NEM and REG provide customers with financial value (e.g. bill credits or net metering credits) for a defined period of time. For this reason, the study estimates program committed spending as the net present value (NPV) of customer bill credits made under both programs over the lifetime of the contracts in order to provide a full assessment of committed program spending[87,88].

Figure 6-7. Estimated Program Costs and Committed Spending for Customer-Sited Solar Program (Mid Scenario)

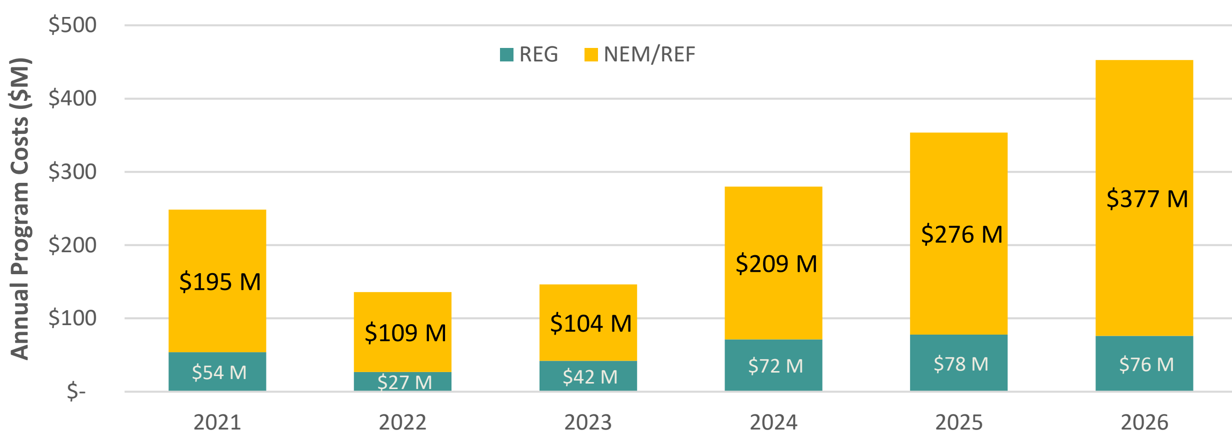


Table 6-5. Estimated Program Costs and Committed Spending for REG Program (Mid Scenario)

Program		2021	2022	2023	2024	2025	2026	Average	Total
REG	REG Bill Credit (NPV) [88]	$51.3M	$25M	$39.9M	$68.8M	$75.3M	$73.3M	$55.6M	**$333.7M**
	REG Admin	$2.4M	$1.9M	$2.2M	$2.7M	$2.8M	$2.8M	$2.5M	**$14.8M**
	Total	**$53.7M**	**$27M**	**$42.1M**	**$71.5M**	**$78.1M**	**$76.1M**	**$58.1M**	**$348.6M**

Table 6-6. Estimated Program Costs and Committed Spending for NEM + REF Program (Mid Scenario)

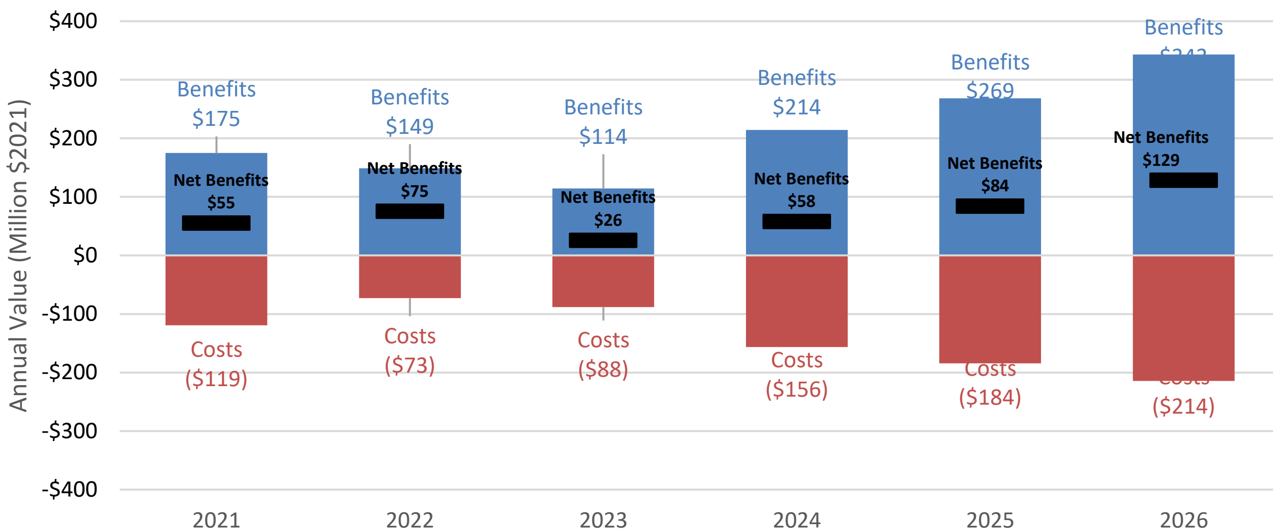
Program		2021	2022	2023	2024	2025	2026	Average	Total
NEM + REF	Net Metering Credits (NPV) [87]	$176.4M	$98.3M	$95.9M	$196.1M	$263.3M	$365.5M	$199.2M	**$1195.4M**
	NEM Admin	$1.5M	$1.5M	$1.5M	$1.5M	$1.5M	$1.5M	$1.5M	**$9M**
	REF Incentives	$16.7M	$8.7M	$6.7M	$10.6M	$10.4M	$9.3M	$10.4M	**$72.8M**
	REF Admin	$0.3M	$0.3M	$0.3M	$0.3M	$0.3M	$0.3M	$0.3M	**$1.8M**
	Total	**$194.8M**	**$108.8M**	**$104.4M**	**$208.5M**	**$275.5M**	**$376.6M**	**$211.4M**	**$1268.7M**

[87] Net metering credit value is based on the estimated financial value to participating customers from offsetting their electricity loads and receiving credits for production exported to the grid.
[88] REG bill credit value includes the estimated bill credits issued to participating customers during their REG contract lifetime as well as bill credits issued after the end of their REG contracts assuming customers are compensated at retail rates.

Program Benefits

Considering both the benefit and cost value streams from the RI Test, the forecasted solar adoption under both programs was found to be cost-effective from a societal perspective during the study period as shown in Figure 6-8.[89] The forecasted solar uptake is expected to generate an average of $76 million in lifetime net benefits during the study period.

Figure 6-8. Benefits and Costs of Customer-Sited Solar Deployment (Mid Scenario)



Note: The calculation of benefits and costs does not include economic development benefit due to the lack of an estimated GDP multiplier for solar PV programs in Rhode Island.

6.3.2 Low and Max Scenario

To assess how different market and policy conditions could impact solar adoption in Rhode Island, two additional achievable potential scenarios (Low and Max) are modeled. Specifically, the two scenarios reflect different factors that could impact the market after the ITC phase-out as follows[90]:

- **In the Low achievable potential scenario,** the study assumes that policy support for customer-sited solar is reduced in the state. Specifically, the REG program is assumed to have more constrained allocation caps (one-half what is assumed under the base case), and incentives offered by the REF program are assumed to be discontinued. Furthermore, PV cost reductions are assumed to be slower than projected in the base case to reflect the impacts of solar tariffs imposed by the federal government on PV modules as well as increasing margins by solar installers to maintain industry profitability.

[89] Given that the RI Test applies a societal perspective to assessing the benefits and costs of distributed generation, incentives and compensation to customers are not considered a cost (as they represent a transfer payment from one party to another). However, the cost-effectiveness analysis does consider the administrative costs associated with the programs as well as the net lifetime system costs incurred by customers (i.e. Installation and O&M costs minus any federal incentives).
[90] Key scenario inputs and assumptions are presented in Appendix F.

- **In the Max achievable potential scenario,** the study assumes that policymakers and the solar industry in Rhode Island would take measures to counteract the implications of the ITC phase-out. Specifically, no allocation caps for the REG program are assumed to be in place. Additionally, incentives offered through the REG program are assumed to be reduced more gradually (being held steady for 2 years and stepped down at a slower pace than in the base case). Furthermore, the solar industry is assumed to reduce margins and soft costs to offer competitive prices to customers to maintain the industry's growth.

Figure 6-9 below shows the projected annual and cumulative installed capacity during the study period under the Base Sase (Mid) and the two alternative scenarios. The results highlight that more aggressive policy and market actions to mitigate the impacts of ITC could increase total installed capacity during the study period by 18% (273 MW relative to 233 MW under base case). Conversely, reduced policy support and high PV costs could reduce market potential by 19% (195 MW relative to 233 MW under base case). More specifically, the results highlight the following takeaways:

- **Under the Low scenario**, the reduced policy support for customer-sited solar in the form of cancellation of the REF program rebates and more constrained REG allocation caps will result in a sharp drop in adoption in the near-term (i.e. 2021 and 2023). In the longer term (2024 – 2026), natural un-incented market demand for solar will still increase significantly over the study period.
- **Under the Max scenario,** a more moderate decline of incentives coupled with reductions in PV system costs can counteract the impacts of the ITC phase-out to some extent in the near-term (particularly in the residential sector) and maintain market growth in the latter years of the study. On the other hand, increases in REG caps are unlikely to result in significant changes to the market forecast, as the business case for NEM becomes more advantageous for customers and allocation caps are not met.

Figure 6-9. Forecasted Annual (top) and Cumulative (bottom) Customer-Sited Solar Capacity Additions (All Scenarios)

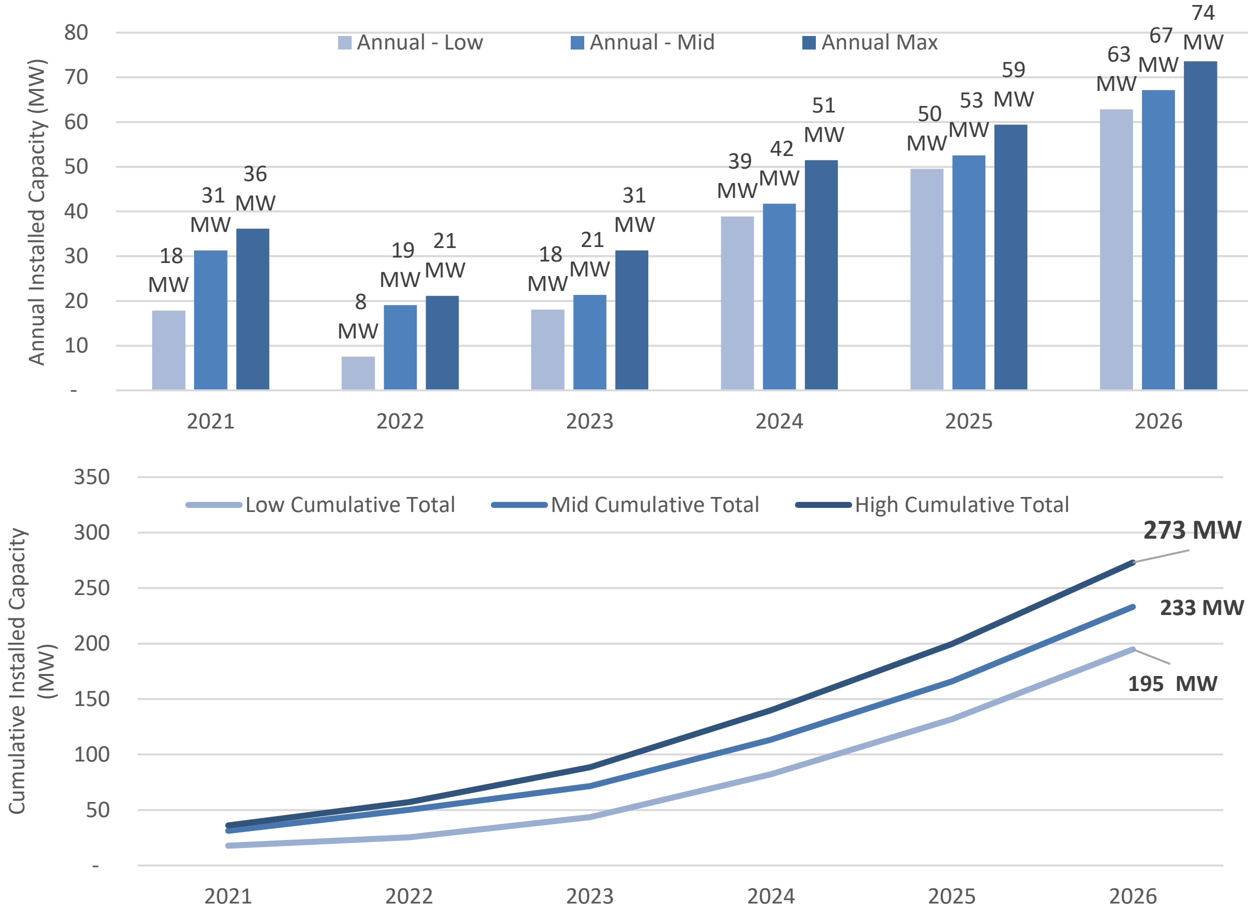


Table 6-7 below highlights the total number of installed systems and capacity in each sector over the entire study period.

Table 6-7. Total Installed Customer-sited Solar Systems by Sector and Scenario (2021-2026)

Scenario	Sector	Cumulative Installed Systems	Cumulative Installed Capacity (MW)
Low	Residential	11,580	70
	Commercial	908	122
	Industrial	17	3
	Total	**12,504**	**195**
Mid *(Base)*	Residential	14,159	85
	Commercial	1,087	144
	Industrial	28	4
	Total	**15,274**	**233**
Max	Residential	18,627	112
	Commercial	1,202	156
	Industrial	30	4
	Total	**19,860**	**273**

6.3.2.1 Load Impacts

Changes in adoption under the Low and Max scenarios respectively will contribute to nearly a proportional impact on load (both energy and peak savings), as shown in Table 6-8 and Table 6-9 below. For example, cumulative energy savings are expected to be between 256 and 358 GWh (relative to 306 GWh under the base case). This corresponds to approximately 3.3% to 4.6% of forecasted electricity sales in 2026. Similarly, peak load reductions from the forecasted adoption can increase to 72 MW in 2026. Over the lifetime of systems installed within the study period, customer-sited solar will save between 7.35 TWh (Low) and 10.3 TWh (Max).

Table 6-8. Load Impacts of Customer-Sited Solar Deployment (All Scenarios)

Savings	Sector	2021	2022	2023	2024	2025	2026
Cumulative Savings (GWh)	Low	24	34	58	109	174	256
	Mid	41	67	95	149	218	306
	Max	48	76	117	184	262	358
Cumulative Peak Savings (MW)	Low	7	10	17	28	39	54
	Mid	7	20	25	35	47	63
	Max	7	22	29	41	55	72

Table 6-9. Incremental Lifetime Energy Savings from Customer-Sited Solar Deployment (All Scenarios)

Savings	Sector	2021	2022	2023	2024	2025	2026	Average	Total
Incremental Lifetime Savings (GWh)	Low	679	287	686	1,470	1,866	2,363	**1,225**	**7,350**
	Mid	1,191	721	805	1,572	1,974	2,518	**1,463**	**8,780**
	Max	1,370	797	1,181	1,937	2,227	2,753	**1,711**	**10,266**

6.3.2.2 Program Costs

Table 6-10 below shows estimated program costs under each scenario for both REG and NEM+REF. As expected, program costs will vary significantly with changing uptake under each scenario. Under the Low scenario, program spending would be decline by 20% relative to the Mid scenario. Conversely, under the Max scenario, program costs would increase by 12% to $1.8B over the study period. The program cost estimates consider all committed program spending. Specifically, the values include REF program incentives, net metering credits dispersed to customers over the lifetime of the systems (assumed to be 30 years), REG bill credits paid to customers over the lifetime of the contracts as well as program administrative costs for REF, NEM and REG.

Table 6-10. Annual Customer-Sited Solar Program Costs (All Scenarios)

Scenario	Program	2021	2022	2023	2024	2025	2026	Average	Total
Low	REG	$32M	$9M	$30M	$53M	$45M	$42M	**$35M**	**$212M**
	NEM[91]	$92M	$37M	$88M	$214M	$297M	$404M	**$189M**	**$1,132M**
	Total	**$124M**	**$47M**	**$119M**	**$267M**	**$341M**	**$446M**	**$224M**	**$1,344M**
Mid	REG	$54M	$27M	$42M	$72M	$78M	$76M	**$58M**	**$349M**
	NEM +REF	$195M	$109M	$104M	$209M	$276M	$377M	**$211M**	**$1,269M**
	Total	**$249M**	**$136M**	**$147M**	**$280M**	**$354M**	**$453M**	**$270M**	**$1,617M**
Max	REG	$65M	$34M	$55M	$93M	$98M	$115M	**$76M**	**$459M**
	NEM +REF	$203M	$115M	$161M	$240M	$287M	$343M	**$225M**	**$1,348M**
	Total	**$268M**	**$148M**	**$215M**	**$333M**	**$385M**	**$458M**	**$301M**	**$1,807M**

Note: Values presented here include upfront incentive payments, administrative costs, and the NPV of REG bill credits and net metering credits dispersed to customers over a defined period of time.

Considering the benefits and costs of the forecasted customer-sited solar uptake under the three scenarios using the RI Test highlights the generation of average lifetime net benefits of $68 - $82M each year over the study period.[92]

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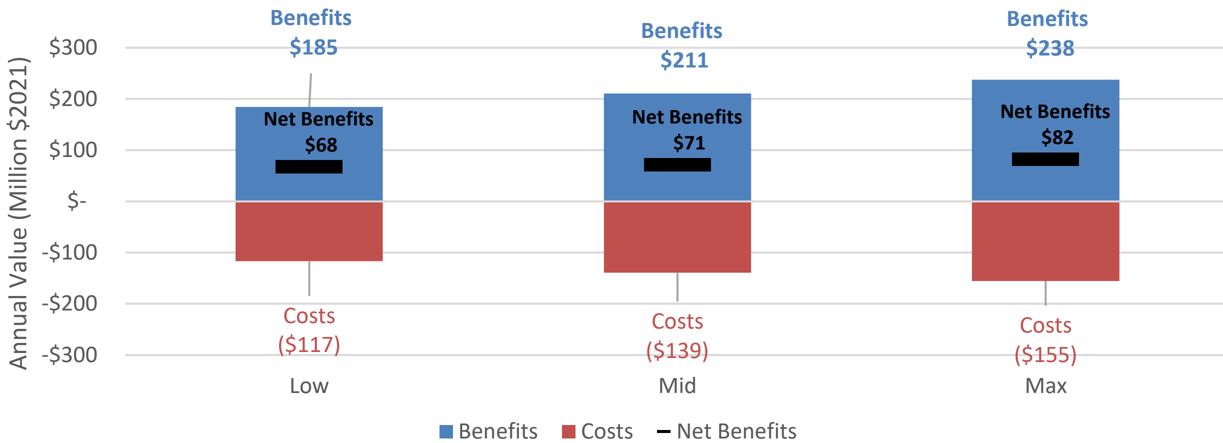
[91] The REF program is assumed to be discontinued in the Low scenario.

[92] For a full description of the costs and benefits included in the RI Test, please see the Attachment 4 - 2020 Rhode Island Test Description as filed with National Grid's 2020 EEPP (Docket No. 4979) accessible at: http://www.ripuc.ri.gov/eventsactions/docket/4979-NGrid-EEPP2020%20(10-15-19).pdf

Figure 6-10. Average Lifetime Benefits and Costs Generated Each Year (2021-2026) from Customer-sited Solar (All Scenarios)



Note: The calculation of benefits and costs does not include economic development benefit due to the lack of an estimated GDP multiplier for solar PV programs in Rhode Island.

6.4 Storage-Paired Solar Uptake

Across the United States, solar installers indicate that 35% of their customers have expressed interest in energy storage, with 15% of systems installed in 2019 being storage-paired solar[93]. Despite recent growing interest in behind-the-meter storage, the momentum the market has gained in the past few years will also likely diminish with the phase-out of the ITC. To assess the portion of solar uptake in Rhode Island that will be storage-paired over the study period, the study models the economics of standalone and storage-paired systems considering both the incremental benefits and costs to customers.

Overall, the analysis shows a relatively limited business case for storage deployment in Rhode Island during the study period, with nearly 500 systems forecasted to be installed during the study period (i.e. between 2021 and 2026) under the base case with a total capacity of 8.8 MW (17.6 MWh).

In the residential segment, the analysis shows that only 1 – 3% of the solar deployment will be storage-paired systems. This is primarily due to the unfavorable economics for storage in the absence of dynamic rates, energy arbitrage opportunities and/or compensation mechanism for distributed generation that encourage in-house consumption as opposed to exports[94]. During the study period, residential storage uptake is projected to be mostly early adopters who are motivated by non-financial factors (e.g. resiliency or general interest in emerging technologies) and revenues from Demand Response (DR) programs.

In the commercial segment, the potential for demand charge management coupled with revenue from DR programs create a more favourable business case for storage-paired solar relative to the residential sector. The study's forecasts indicate that 19 – 24% of deployed solar systems within the study period will be storage-paired[95]. Despite the more favourable economics, the absence of dynamic rates, energy arbitrage opportunities or an alternative compensation mechanism for grid exports in the commercial sector will likely limit the potential for storage-paired solar.

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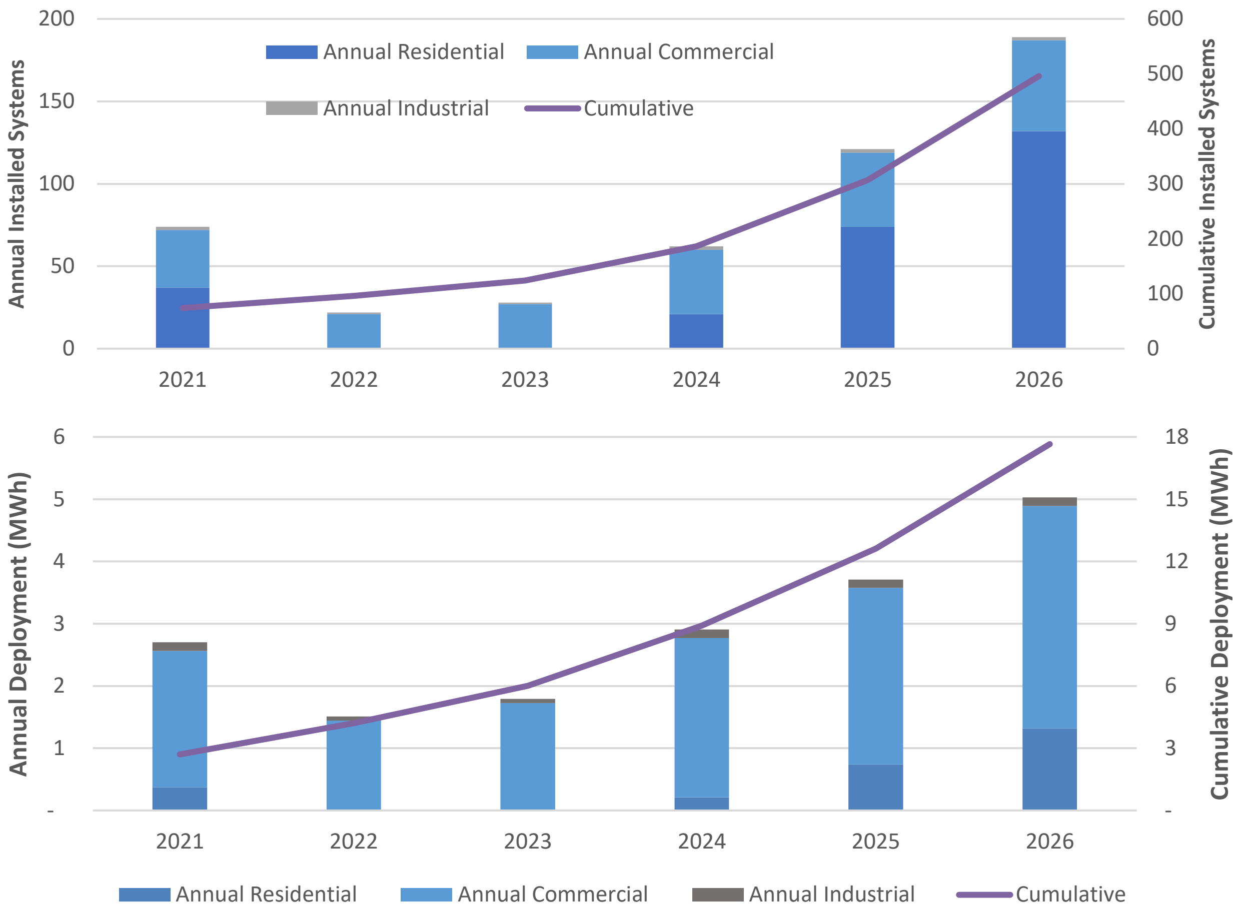
[93] EnergySage (2019), Solar Installer Survey: 2019 Results

[94] For example, mechanisms that offer lower compensation to distributed generation provide customers with an incentive to reduce grid exports and use the produced energy "in-house" either through reducing the size of installed systems or installing battery storage.

[95] Additional uptake of stand-alone storage (i.e. not coupled with solar PV) may be observed for customers with significant peak demand charges that can be offset through load shifting.

Figure 6-11. Forecasted Customer-sited Storage-paired Solar Uptake (Mid Scenario)



6.5 Value of Solar Assessment

Several jurisdictions across the U.S. have conducted studies to assess the value that distributed generation and Distributed Energy Resources (DERs) broadly bring to the grid. These studies often aim to develop rate designs and tariffs for DERs to compensate them for the true value they bring to the grid. As expected, the outcomes of these studies vary significantly due to differences in local context of each market and the used inputs/assumptions. However, the largest driver of divergence between the studies is often the value streams the studies include – or do not include - and the underlying methods used to quantify them.

Through a scan of value of distributed solar assessment studies and meta-analysis studies, the study captures approximately 50 relevant studies and identifies key benefits that distributed solar brings to utilities, grids and society, as outlined in the table below. While no studies comprehensively evaluate all value streams for DERs, there is general recognition of a few key value streams. The comparison of these value streams relative to components of the RI Test in Table 6-11[96] highlights that the majority of these

[96] While the table highlights the benefits, there are also costs associated with distributed solar, including system costs, utility revenue loss, interconnection costs, program administrative and incentives among other factors.

benefits, with the exception of grid resiliency, are considered and quantified in the RI Test either directly or through embedded assumptions in other value streams[97].

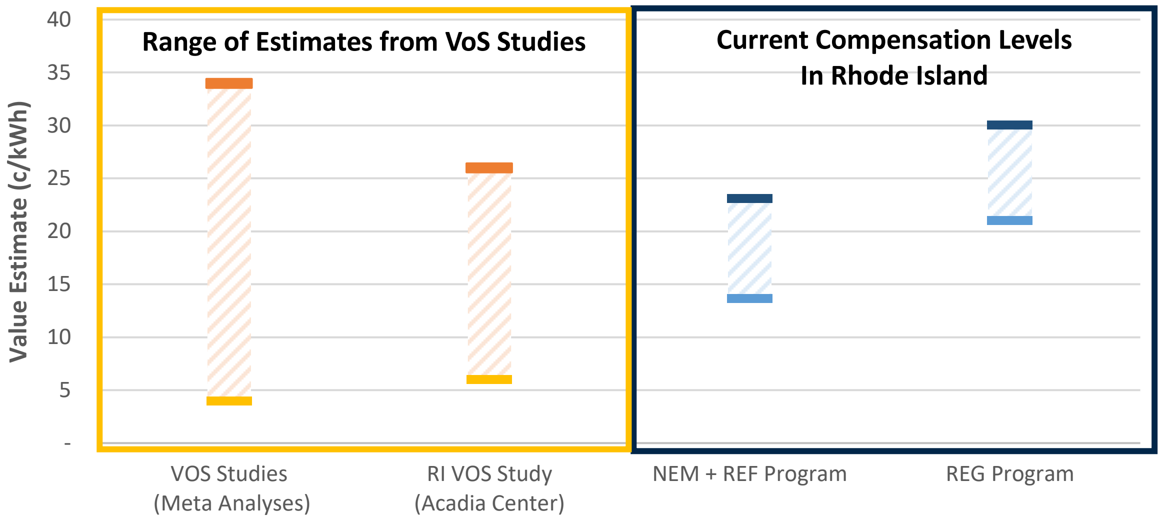
Table 6-11. Key Benefit Components in Value of Solar Studies

VOS Study Benefit Components	Description	Commonly Included?	Included in RI Test?
Wholesale Energy Market Costs	Avoided cost of marginal generation displaced by the solar resource (includes fuel and O&M)	Yes	Yes
Wholesale Capacity Market Costs	Avoided cost of acquiring capacity generation to meet reliability needs	Yes	Yes
Avoided Transmission Costs	Avoided cost of transmission system upgrades to meet peak demand requirements	Yes	Yes
Avoided Distribution Costs	Avoided cost of distribution system upgrades to meet peak demand requirements	Yes	Yes
Line Losses	An adder to reflect improved system efficiency (i.e. less generation required) from locating resources closer to load and avoiding losses from electricity transmission.	Yes	Yes
Avoided Environmental Compliance Costs	Reduced need to hold allowances/credits and/or pay environmental program compliance costs related to emissions (e.g. RGGI)	Yes	Yes
Grid Support Services	The value of ancillary services that can be provided by the solar resource (balancing, voltage control, etc.)	Sometimes	Yes
Price Suppression	Market price reduction impacts from reduced demand (energy and capacity)	Sometimes	Yes
Avoided RPS Compliance Costs	Cost to utilities to acquire renewable energy (credits) and/or make alternative compliance payments	Sometimes	Yes
Fuel Price Hedge	Reduced exposure to market price volatility for fossil fuels as well as exchange rates	Sometimes	Yes
Societal Benefits	Additional benefits such as social cost of carbon, SO2, NOx, etc. Difference between societal cost and existing environmental compliance costs	Sometimes	Yes
Economic Development and Job Creation	Additional benefits such as GDP and jobs from installing solar, O&M, and (potential) bill savings	No/Rarely	Yes
Grid Resiliency	Additional benefit of having distributed resources that are closer to load, increasing security and stability of supply	No/Rarely	No

As shown in Figure 6-12 below, the estimates of the value of solar range from 4 to 36 cents per kWh in the reviewed studies. The range reflects jurisdictional as well as methodological differences between the studies. In addition, varying azimuth and tilt scenarios can generate differing values to the grid and society, as was shown in a Rhode Island-specific VOS study by the Acadia Center in 2015, which found a range of 6 to 26 cents per kWh. Comparing the results with Net Energy Metering and Renewable Energy Growth program compensation levels in Rhode Island highlights that current compensation levels fall within the range of the reviewed studies.[98]

[97] Improved reliability values within the RI Test were assumed to be a proxy for the value of grid support services.
[98] NEM compensation level reflects the average large commercial (lower end of the range) and residential (high end) retail rates as well as the value of REF incentives received levelized over the lifetime of the system. The REG compensation level range reflects the recommended 2020 REG ceiling prices for commercial solar (lower end of range) and small solar I (high end).

Figure 6-12. Summary of Value of Distributed Solar Estimates and Current Solar Compensation Levels in Rhode Island



Temporal and Locational Value

While these studies offer a system-wide estimate of the value of solar, it is becoming increasingly important to consider both the "when" and "where" of DERs. For examples, distributed solar PV can provide higher benefits to the grid in locations on the distribution system where they can serve as non-wire alternatives that avoid or defer infrastructure upgrades. Similarly, solar production that is coincident with system peak can reduce/avoid peak loads and avoid/defer investments in generation, transmission, or distribution assets.

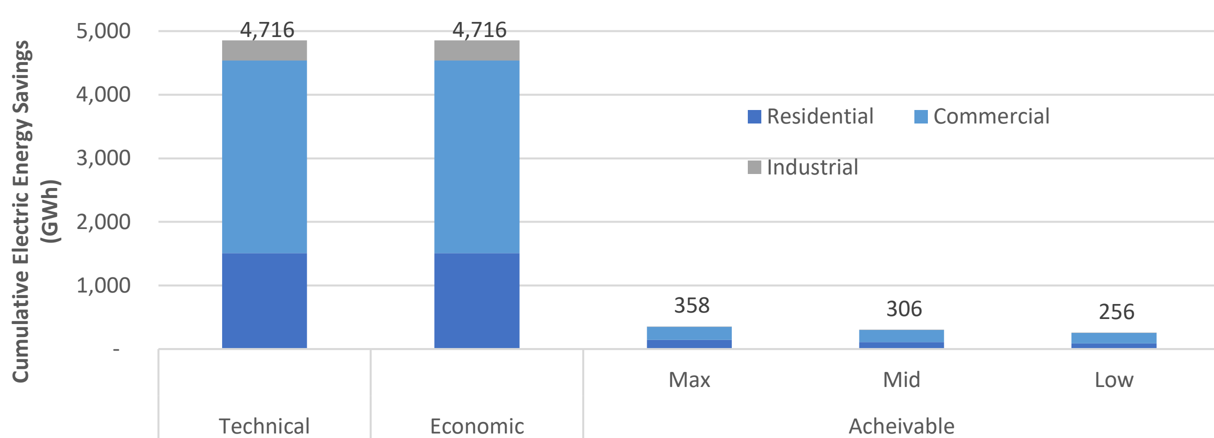
6.6 Key Takeaways

The results of the analysis to estimate the technical, economic, and achievable potential of customer-sited solar in Rhode Island are summarized in Figure 6-13 below. The results highlight the following takeaways:

- **The feasible technical potential for solar deployment in Rhode Island is estimated at 4 GW of capacity**, corresponding to 4.7 TWh of annual energy production. The majority of the identified technical potential (60%) is in the commercial segment due to the larger building sizes in the segment.
- **All technically feasible customer-sited solar deployment is found to be cost-effective under the RI Test.** Considering both benefits and costs of solar deployment, the analysis estimates an average annual societal net-benefit of $76 - $119M.
- **195 MW (Low) to 273 MW (Max) of customer-sited solar capacity are forecasted to be deployed in Rhode Island over the study period**. Specifically, the achievable market potential will highly depend on policy and market response after the ITC phase-out. The forecasted adoption will bring between 256 GWh (Low) and 358 GWh (Max) of cumulative energy savings from customer-sited solar penetration by 2026 as well as up to 72 MW (Max) in peak demand reductions. While the majority of customer-sited solar installations are expected to be in the residential sector, the non-residential installs dominate the market in terms of installed capacity due to the larger installation sizes.

- **Limited potential for the uptake of storage-paired solar in Rhode Island is forecasted over the study period due to the unfavourable economics.** This is primarily the case in the residential sector, however higher uptake is forecasted in the commercial sector due to the benefits of peak demand charge reductions.
- **A meta-review of value of solar studies highlights the multitude of benefits distributed solar brings utilities, the grid and society**, and shows a range of value estimates from 4 to 36 cents per kWh reflecting jurisdictional contexts as well as methodological differences across the studies. Additionally, the review shows that the majority of these benefits are considered and quantified in the RI Test.

Figure 6-13. Summary of Distributed Solar Potential in Rhode Island (2021-2026)



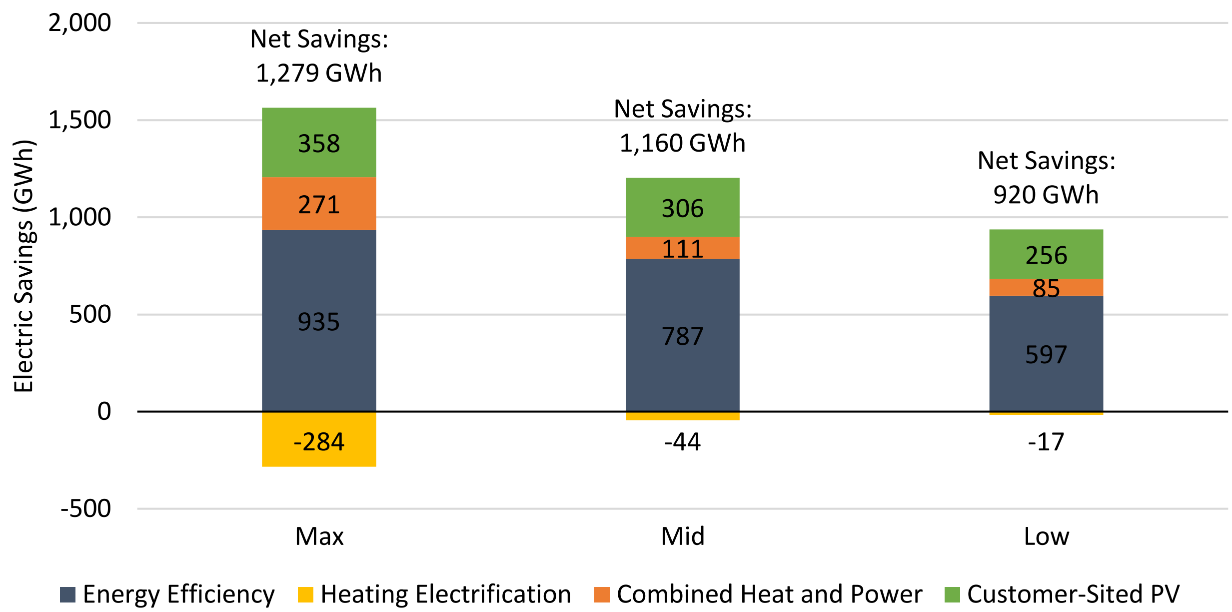
7 Combined System Impacts

The following chapter combines the results from each module to present the combined system-level impact of savings estimated within each module of the MPS. For each saving stream (e.g. electric, natural gas, etc.), the net impact of each saving stream in 2026 is combined and presented. This is then followed by the combined impact of these savings on energy sales / peak electric demand over the duration of the study period for each scenario. Finally, a graphical illustration of each saving stream's impact on energy sales / peak demand over the study period under the Mid scenario is provided for each saving type.

7.1 Electricity

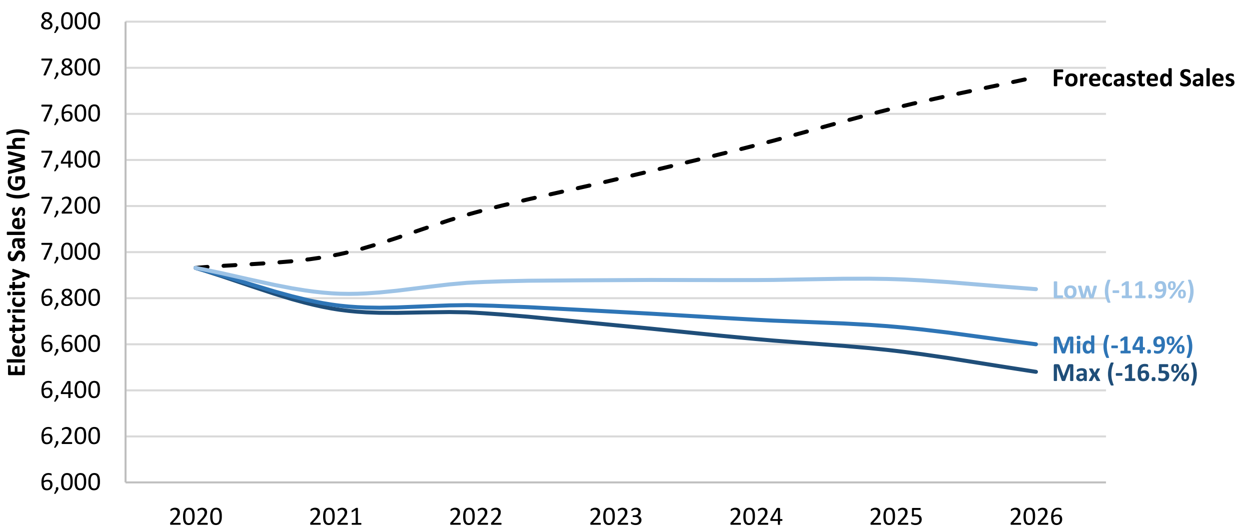
Electric savings from energy efficiency (EE), combined heat and power (CHP), and customer-sited solar PV will outweigh any increase in electric consumption resulting from heating electrification (HE). By 2026, the combined savings will range between 920 GWh (Low) to 1,279 GWh (Max) as shown in Figure 7-1.

Figure 7-1. Combined Electric Savings in 2026 (All MPS Modules)



The combined impact of all saving streams will reduce forecasted 2026 electric sales by 11.9% to 19.9% as shown in Figure 7-2. Under all scenarios, the combined impact eliminates any net growth in electricity sales over the study period.

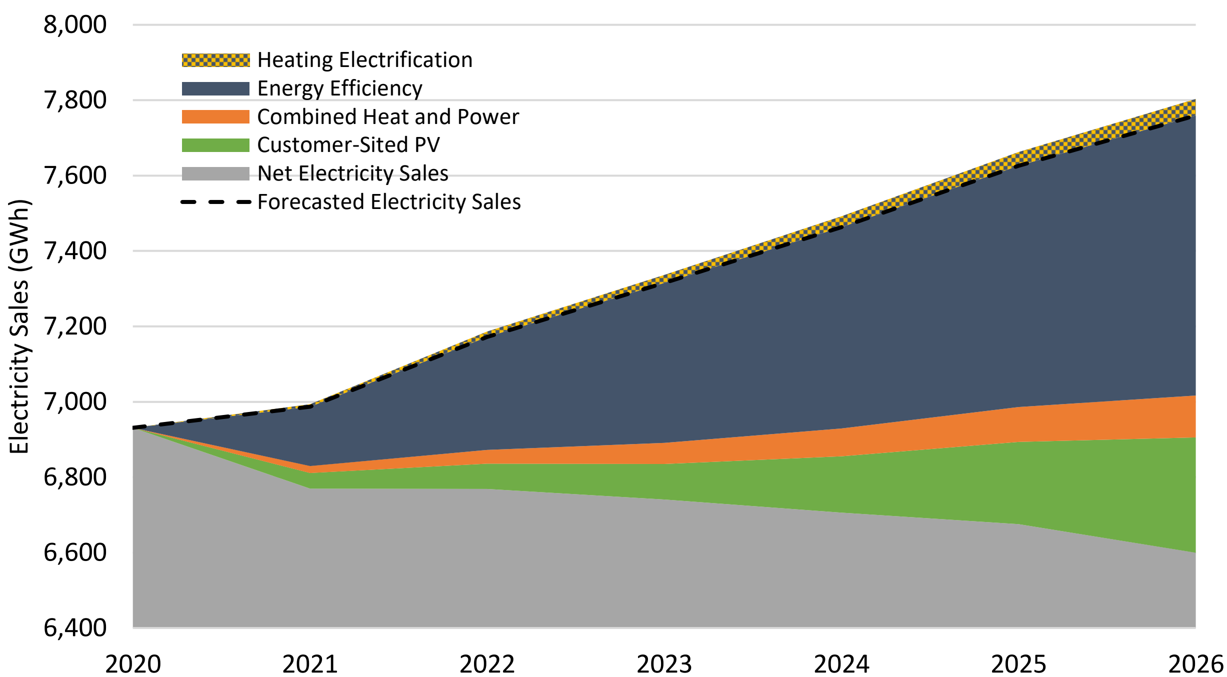
Figure 7-2. Combined Impact on Electricity Sales for Each Scenario (2021-26; All MPS Modules)



Note: Y-axis in above figure does not begin at zero.

Figure 7-3 illustrates the contribution of each module's impact on electricity sales over the study period for the Mid scenario.

Figure 7-3. Combined Impact on Electricity Sales by Savings Stream (Mid Scenario; All MPS Modules)

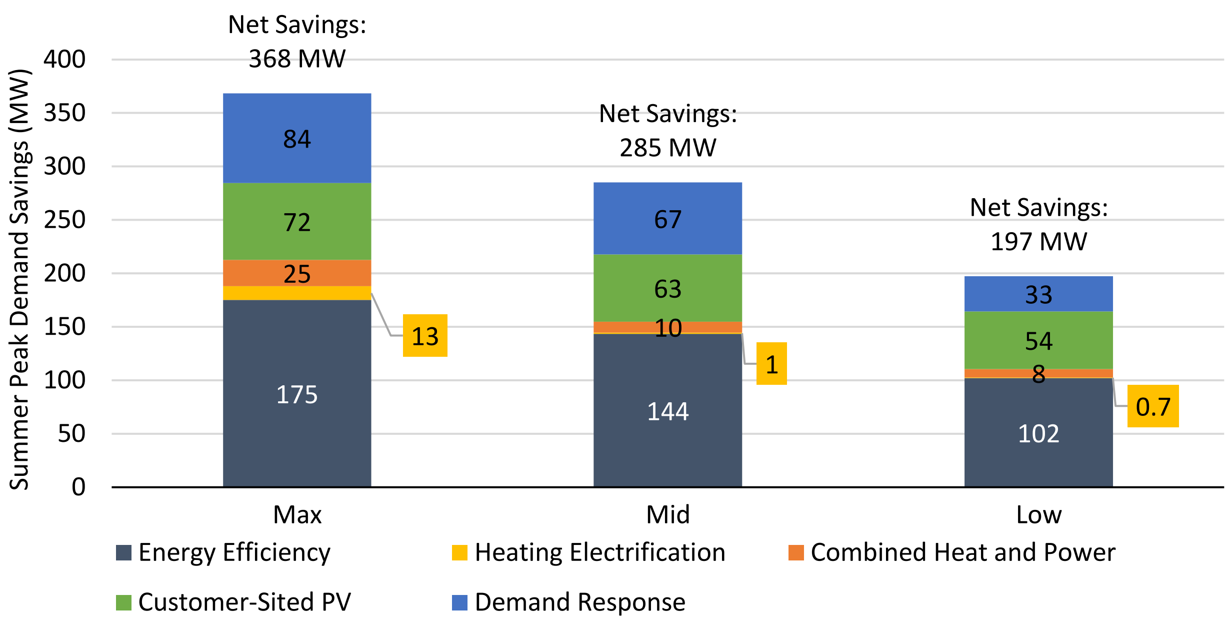


Note: Y-axis in above figure does not begin at zero.

7.2 Electric Demand

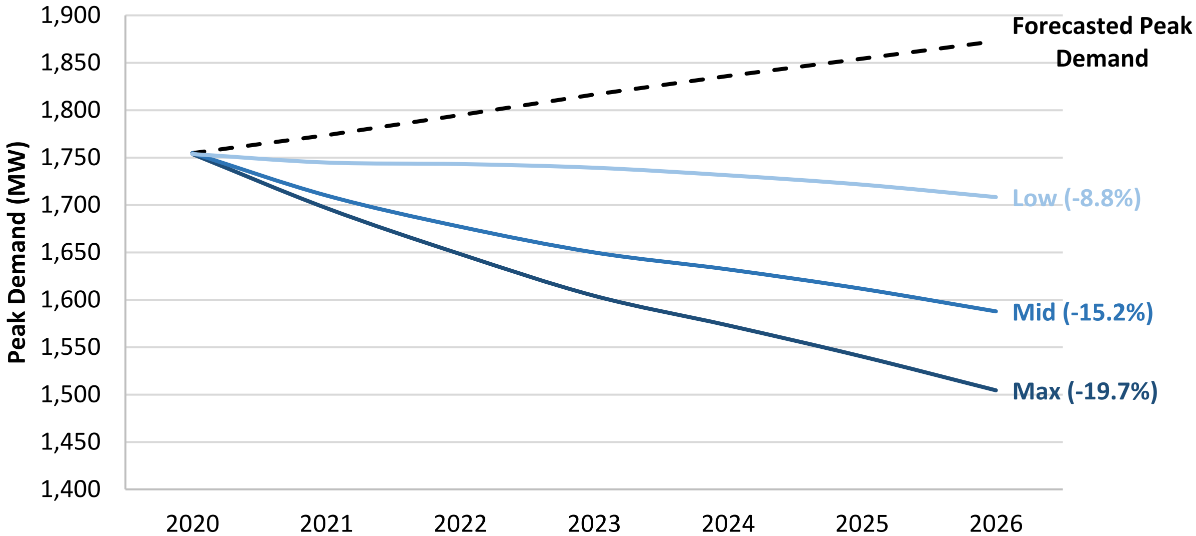
Savings from each module contribute to reducing peak electric demand in Rhode Island (i.e. no module estimated a net *increase* in peak demand resulting from measure adoption). Rhode Island's current peak electric demand typically occurs on hot summer weekday afternoons and is not expected during the study period. As shown in Figure 7-4, the combined impact of each saving stream will reduce peak demand by 297 MW (Low) to 368 MW (Max) in 2026.

Figure 7-4. Combined Demand Savings in 2026 (All MPS Modules)



The combined impact of all saving streams will reduce the forecasted 2026 peak electric demand by 8.8% to 19.7% as shown in Figure 7-5. As further explained in Chapter 5, heating electrification contributes to peak demand savings due to the provision of more efficient air conditioning from the installation of heat pumps for space heating. Under all scenarios, the combined impact eliminates any net growth in peak demand over the study period.

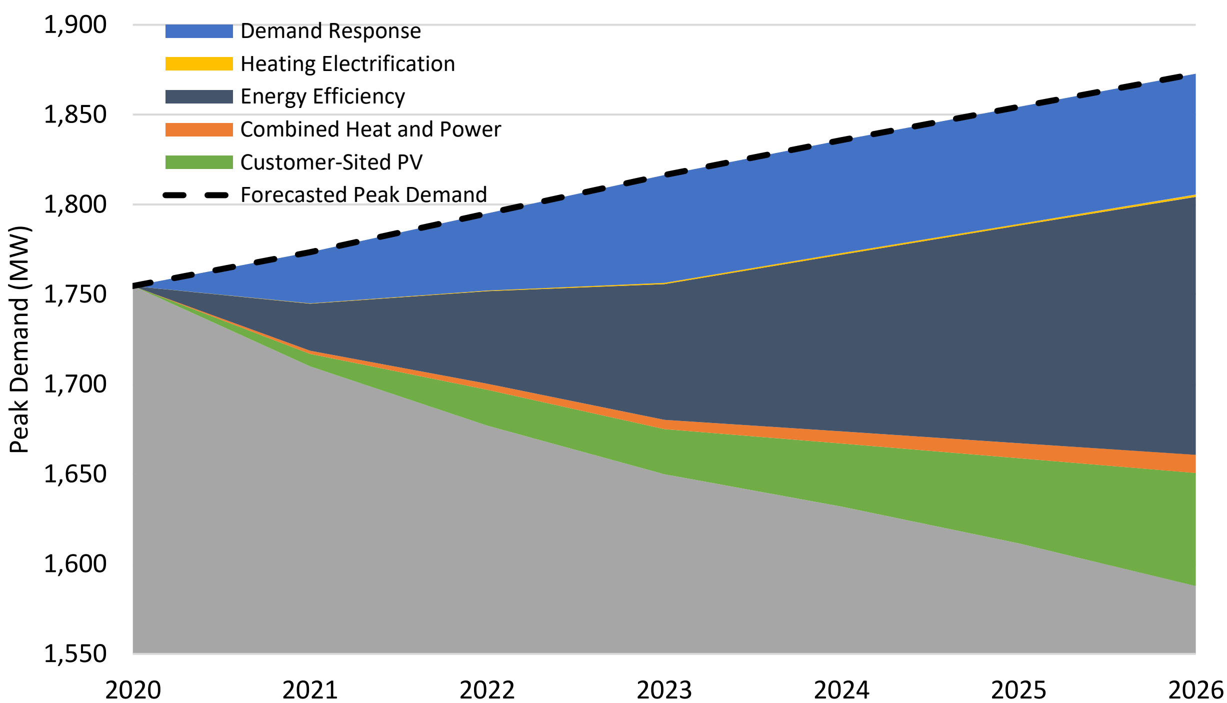
Figure 7-5. Combined Impact on Electric Peak Demand (All MPS Modules)



Note: Y-axis in above figure does not begin at zero.

Figure 7-6 illustrates the contribution of each saving stream's impact on electricity sales over the study period for the Mid scenario.

Figure 7-6. Combined Impact on Peak Electric Demand by Savings Stream (Mid Scenario)

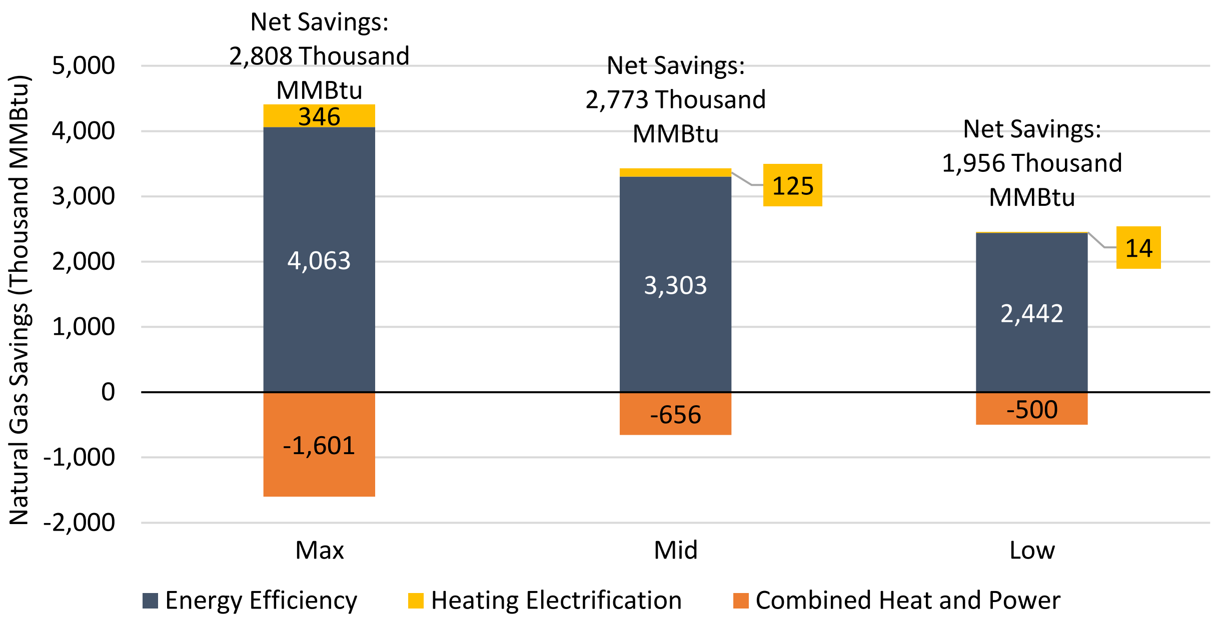


Note: Y-axis in above figure does not begin at zero.

7.3 Natural Gas

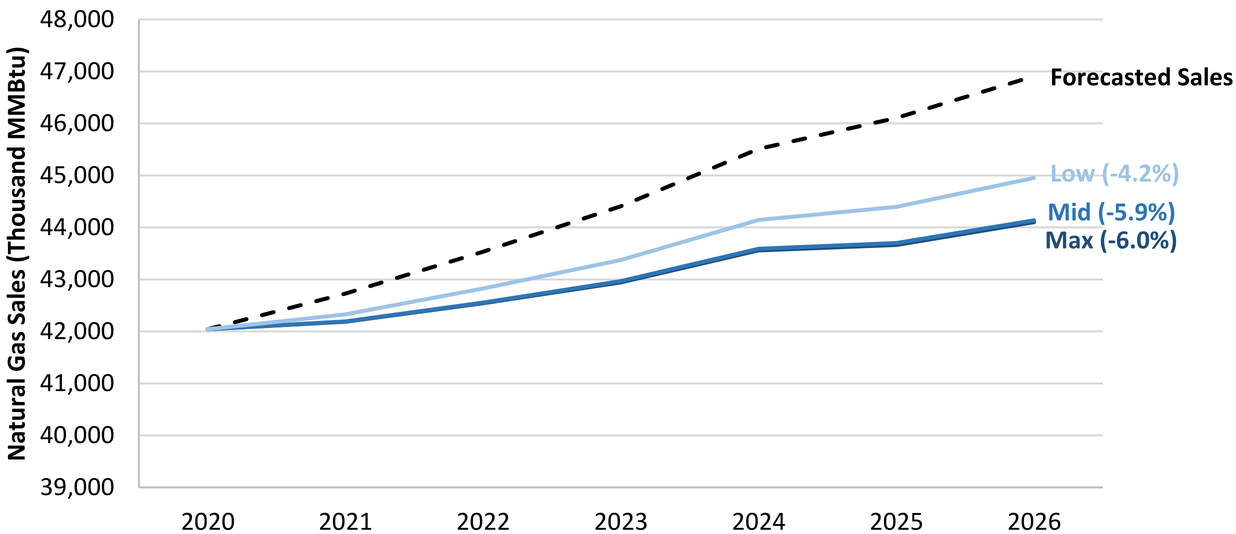
Natural gas savings from EE and HE will outweigh any increase in natural gas consumption resulting from CHP. In 2026, the combined impact will range between 1,959 thousand MMBtu (Low) to 2,808 thousand MMBtu (Max) as shown in Figure 7-7. Most natural gas savings come from efficiency measures. Savings from heating electrification measures is relatively small due to most non-CHP technical natural gas fuel switching savings failing economic screening as discussed in Chapter 5. While there is substantial growth in net impact between the Low and Mid scenarios, the net impacts of the Mid and Max scenarios are similar primarily due to a substantial increase in natural gas consumption under the Max scenario in the CHP module. This substantial growth mostly negates the increase in natural gas savings from the other modules – particularly energy efficiency.

Figure 7-7. Combined Natural Gas Savings in 2026 (All MPS Modules)



The combined net impact of all saving streams will reduce forecasted 2026 natural gas sales by 4.2% to 6.0% as shown in Figure 7-8. Net natural gas sales continue to grow over the study period.

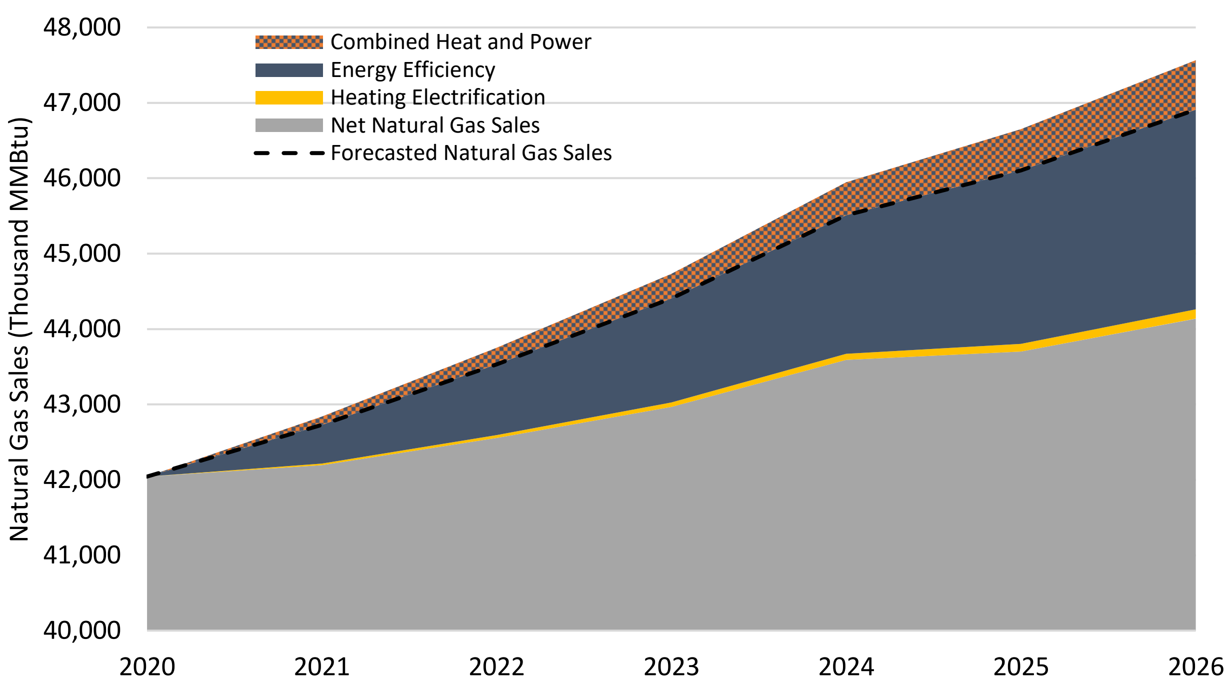
Figure 7-8. Combined Impact on Natural Gas Sales (All MPS Modules)



Note: Y-axis in above figure does not begin at zero.

Figure 7-9 illustrates the contribution of each saving streams' impact on natural gas sales over the study period for the Mid scenario.

Figure 7-9. Combined Impact on Natural Gas Sales by Savings Stream (Mid Scenario)

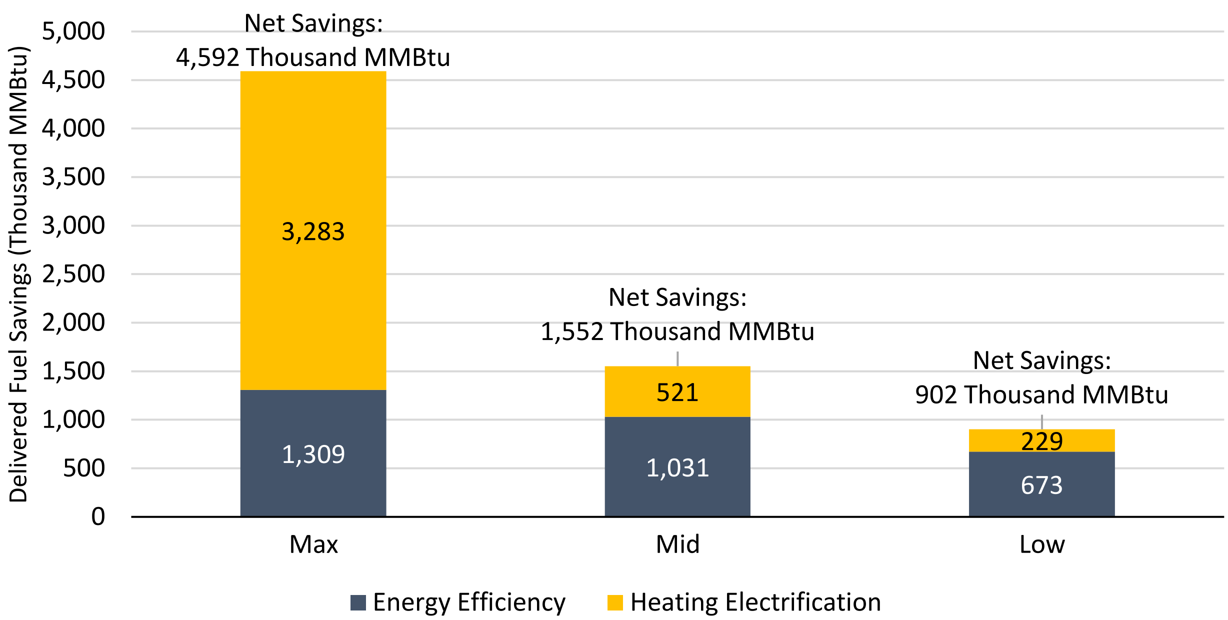


Note: Y-axis in above figure does not begin at zero.

7.4 Delivered Fuels

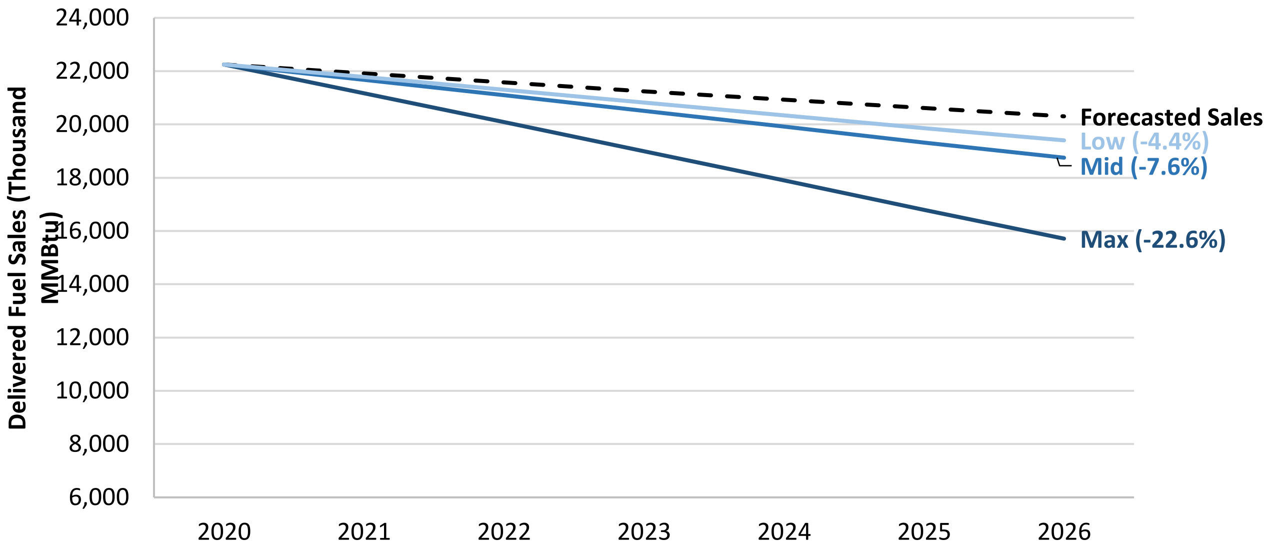
EE and HE both result in delivered fuel savings. By 2026, the combined impact will range between 902 thousand MMBtu (Low) to 4,592 thousand MMBtu (Max) as shown in Figure 7-10. Under the Low and Mid scenarios, efficiency savings eclipse savings from heating electrification. However, under the Max scenario, significant growth in savings from heating electrification cause this saving stream to dominate.

Figure 7-10. Combined Delivered Fuel Savings in 2026 (All MPS Modules)



The combined impact of all saving streams will reduce forecasted 2026 delivered fuel sales by 4.4% to 22.6% as shown in Figure 7-11 – further accelerating the expected decline in delivered fuel sales over the study period.

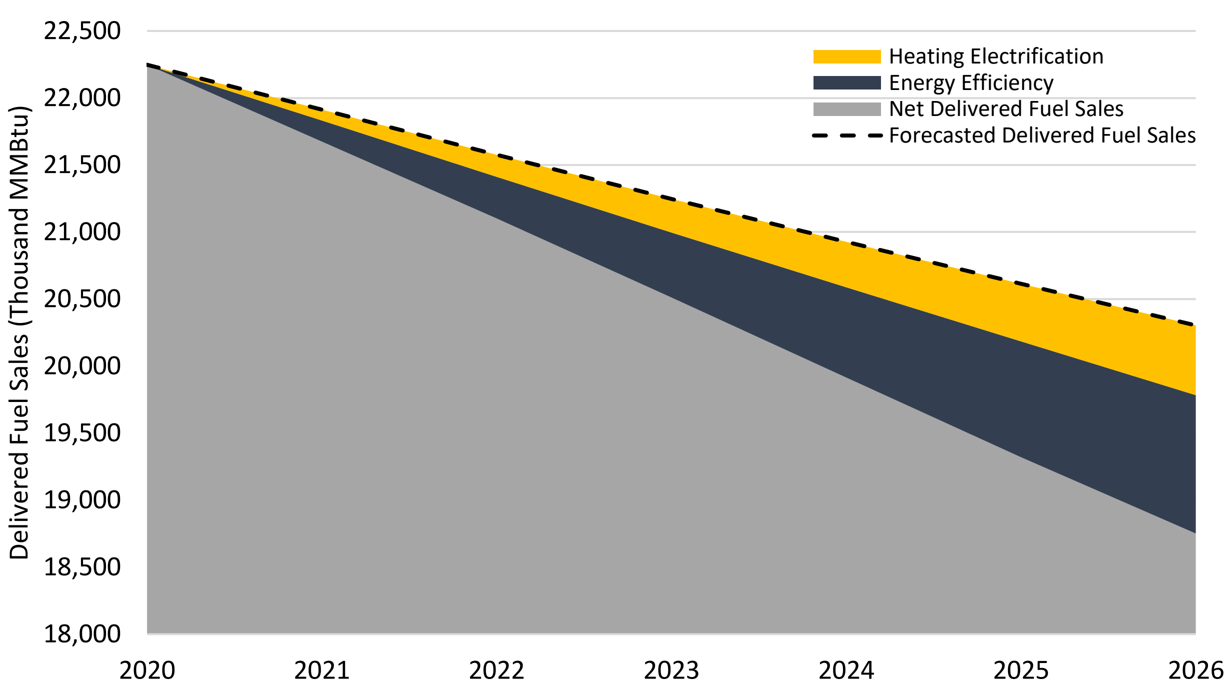
Figure 7-11. Combined Impact on Delivered Fuel Sales (All MPS Modules)



Note: Y-axis in above figure does not begin at zero.

Figure 7-12 illustrates the contribution of each saving stream's impact on electricity sales over the study period for the Mid scenario.

Figure 7-12. Combined Impact on Delivered Fuel Sales by Savings Stream (Mid Scenario)



Note: Y-axis in above figure does not begin at zero.